Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	William Quaintance	
Organization:	ABB Consulting	
Telephone:	919-856-3310	
E-mail:	william.quaintance@us.abb.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ ERCOT	☐	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs and ISOs
☐ MRO	☐	3 — Load-serving Entities
☐ NPCC	☐	4 — Transmission-dependent Utilities
☐ RFC	☐	5 — Electric Generators
☐ SERC	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ SPP	☐	7 — Large Electricity End Users
☐ WECC	☐	8 — Small Electricity End Users
☒ NA – Not Applicable	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment: Agree but delete "or node". It is unnecessary.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: See Q6. Also, from your definition above, a better term would be "directly-connected load loss". This is clear and to the point.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: Most people will think of inconsequential, which often means irrelevant, unimportant, or insignificant. But what you are trying to define is the opposite: load loss that is significant, important, and needs to be**	

prevented. Also, whatever you call it, your examples (UVLS, UFLS, SPS) should be expanded to include unintentional and uncontrolled load loss due to low voltage, high current, impedance relays, etc.	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☐Do not agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment: Agree but adjust language. You are saying "require requirements to be met". Duh. Even if you took out one of them and said "requirements must be met", this is also redundant. The definition of "requirement" is that it is required. How about "Events for which there are strict transmission performance standards that must be met." This may also be slightly redundant, but not as much as the original.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: I don't see any reason to differentiate between "Plant Stability" and "System Stability". These are not commonly separated. A better differentiation would be between generator (or angular) stability and load (or voltage) stability. These are usually independently studied and indendently occurring.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: See Q9.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment: Agree but delete "annual". Unnecessarily restrictive. Aren't there non-annual studies for which the definition of "year one" is important?**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of

variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: No. However, as long as we're talking about it, NERC should set a standard for the definition of the "peak load" to be planned for. Some utilities use the 50% probability peak load. Some use 90%. A big difference that will result in a big difference in how they are prepared for the peak load days. The sensitivity section is not sufficient to address this.
Also, outages of reactive resources should be (and are) in the list of contingencies, not sensitivities.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment: Absolutely.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: First of all, you are not exactly requiring that DSM be considered or analyzed. You have simply listed it as one of the possible solutions. And you should mention the possibility of "integrated plan" in the standard itself. Since DSM is simply optional, let the planners figure out themselves how to consider DSM.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☒

Comment: Any area where there might possibly be an impact. I.e., engineering judgement.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐

Comment: Yes, it helps when considering other issues in the same area. You would know whether or not you can count on a project going in.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐

Comment: It's kind of obvious. If you require a solution to begin with, then if that solution is removed, another solution must be planned. However, if the removed project is not directly related to the study or problem at hand, then engineering judgement will be needed as to whether or not to repeat the study.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☐Do not agree.	Loss of load is not usually considered by tranmission planners. In power flow studies, they look at flows and voltages versus limits. In stability studies, they are looking for angles, speeds, and voltages that stabilize at good values, possibly with temporary excursions less than some limits. How should all these be converted to a loss of load value? Normally we ensure no loss of load <because> we meet thermal, voltage, and stability requirements. Maybe you are saying that planners should not use load tripping as a solution for these violations?
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit	☐Agree. ☐Do not	

followed by System adjustment[1] followed by loss of another Transmission circuit	agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☒

Comment: When talking about breaker outages, I see no reason to differentiate between "non-bus tie" and "bus tie" breakers. Are bus tie breakers inherently more reliable? If the effect on the system due to a tie breaker outage is very bad, then this should be fixed. All other contingencies seem to be slotted based on probability. Shouldn't breakers? Maybe bus tie breakers are weak points in the transmission system that need to be improved.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☒

Comment: Table 1 P3 is a little hard to read/understand. The second column should start out something like "A stuck breaker following the outage of any 1 of the following:" However, P3 will be completely redundant with P2 because, in power flow analysis, there is no difference between a breaker internal fault and a stuck breaker following an external fault. The final outaged equipment is the same. This will cause extra unnecessary work.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	For Table 1 P4, rewrite it to read "Loss of a generator followed by a System adjustment followed by the loss of any one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. A shunt device 5. Single pole of DC line." This structure is easier to read and understand. The order should be like this to match P1. Shunt devices should be included. P3 should be structured similarly.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐

Comment: Yes, this is the purpose of HVDC. It carries the power your want, no more, no less. Both the good and bad of parallel flows are avoided.

[1] System adjustment can be manual or automatic

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐

Comment: Yes, I like this. You can maintain them to be as similar as possible, while still containing the requisite differences.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒

Comment: I don't see any reason to differentiate between "Plant Stability" and "System Stability". These are not commonly separated, and this distinction is not standard in the industry. You should not be inventing a distinction that doesn't exist. A better differentiation would be between generator (or angular) stability and load (or voltage) stability. These are usually independently studied and independently occurring.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment: No. Good idea. A whole plant may be out because of a shortage of cooling water, but this is an orderly shutdown, not a sudden event. It is only appropriate for steady-state.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐

Comment: Yes, but the impact on the models and studies is unknown. Some testing needs to be done with full Eastern and Western Interconnection models to see how they handle motor models at every load. I've performed numerous studies where loads in an entire utility or state have been converted to a large % of motors, and the effect can be shocking. The programs (PSS/E and PSLF) may completely bog down if this is done for a whole interconnection. Many stability problems will be found. We definitely need to transition to this, but with care.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: For multiple, only automatic schemes. For single, only automatic schemes if the loss of MW is shown to be acceptable.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: Every single event will eventually require preparing for the next event. But we cannot plan for every next event. Only specific single and multiple contingencies should be planned for, all flows must be within an established rating of some kind (continuous, 12-hour, 4-hour, 15-min, whatever), and the idea of the "next event" should not be included in a planning standard.

Now maybe there should be a limit as to how short the time of a rating can be in Planning. For example, planning to a 15-min rating is a bad idea. That rating can be used by operators in emergencies, but planners need to do something better. A minimum should be set (e.g. 1 hour rating). I guess if a company wants to use a 15-min rating and then AUTOMATICALLY transition to a 1-hour or 12-hour rating with runback or something else, that is reasonable.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☒

Comment: No. Following a single contingency, all flows must be within some kind of established rating. After that, runback can be used to get under a longer-term rating.

For multiple contingencies, some type of cross-tripping is OK, but runback is too slow and unreliable.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☒
Comment: It makes the system too complex and less reliable. Single contingencies need to be handled without any fancy controls.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: They could be used in the short term until a permanent fix is available. Limit to <5 years.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: In Table 2 P3, more clarification is needed for "above 300 kV". For generators, does that mean those whose POI is >300kV? For transformers, is it the secondary voltage? Also, is the footnote referencing correct?

"A transformer with low side rating above 300 kV" is confusing for transformers with 3 windings. What's the low-side rating of a 500/345/13.8 kV transformer? You should say "a secondary voltage rating above 300 kV" and define "secondary voltage rating" as the second highest voltage rating. This is standard nomenclature. Also, I assume you know that there aren't very many of these. The possibilities are 765/500, 500/345, and 765/345. The first two are uncommon, and the 3rd is only common in AEP and HQ.

In P3, does the 300 kV limit apply to the transmission circuits as well? It is hard to tell.

In R1, you say "Each … shall each …" Delete the second "each", which is redundant. Also delete "required for system performance studies". These words are not part of the requirement. They are part of the justification for the requirement.

Table 1, Extreme Event Descriptions, 3d and 3f are almost identical.

Table 1, P9-1, rewrite as "… (excluding circuits that share common structures for one mile or less)". P9-1 uses "structure" whereas Extreme 2a uses "tower". Make consistent.

P9-2 monopolar is already covered under P4-2.

For all of the multiple contingencies with System Adjustment in the middle, group them together something like this (for those with the same requirements):

"Outage of any one of the following:

1.
2.
3.
4.

followed by System Adjustments followed by outage of any one of the following:

a.
b.
c.
d."

This is easier to understand than separately writing each possible combination of 2.

Overall, the structures of the Tables needs to be made clearer and more consistent. But the ideas are good.

The transition is going to be critical for some of the standards that may require significantly more study work and significant capital investments in transmission infrastructure.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**	
Name:	John Bussman
Organization:	AECI
Telephone:	417-885-9216
E-mail:	jbussman@aeci.org

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☒ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☒	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment: However this could be very subjective.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☒Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.

- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒
Comment: We beklieve that only the worst case would need to be addressed for stability purposes.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒

Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: However, the question as to what is considered committed versus proposed. There are variuos step in the approval process for our company and we are not sure which approval would be considered committed.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to “raise the bar.” Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

[1] System adjustment can be manual or automatic

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☒
Comment: Agree with the statement above as to the timefram regarding stability.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: However, getting all the modleing data is not easy and may take some time.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Whatever the generator is capable of.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: We do not have the capability to have automatic runback at this time. However if an entity does have the capability to perform automatic runback than it should be allowed to prevent overloads. That would be the purpose.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: no comment

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: no comment

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: Based on the p1 to P9 events one would have to model a breaker to breaker instaed of bus to bus. This would be a large undertaking and it seems that it would be more conservative to have a bus to bus model.

Question on P4 - does this apply to all generators on a system or is ther a MW limit to the size of the generator.

P5 Does this mean running N-2 for the 300 KV for all seven cases that would be required. This could take a large amount of computer run time.

We are stating that this change to the standard is not warrented. However, if all these changes are implemented what used to take approximately 1 month to assess will now take approximately 4 months and we are not that big of a system. I assume that the time and manpower to perform all the contingencies has been considered.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)	
Name:	Anita Lee
Organization:	Alberta Electric System Operator
Telephone:	403 539-2497
E-mail:	anita.lee@aeso.ca

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ ERCOT	☐	1 — Transmission Owners
☐ FRCC	☒	2 — RTOs and ISOs
☐ MRO	☐	3 — Load-serving Entities
☐ NPCC	☐	4 — Transmission-dependent Utilities
☐ RFC	☐	5 — Electric Generators
☐ SERC	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ SPP	☐	7 — Large Electricity End Users
☐ WECC	☐	8 — Small Electricity End Users
☐ NA – Not Applicable	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*
			2

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☐Do not agree.
Q1. **Comment: Due to the length of this questionnaire and the different regional approaches to how IRC members meet the TPL requirements, indiividual ISO RTOs have chosen to respond separately. Collectively the IRC SRC provides comments in #43 of this questionnaire.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☐Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☐Do not agree.
Q6. **Comment:**	

Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☐Do not agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.

- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☐
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☐
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in

conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☐
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☐
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to “raise the bar.” Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL

standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the

[1] System adjustment can be manual or automatic

steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected

Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: The Alberta Electric System Operator (AESO) supports the comments from WECC with the exception of Question #19 where the AESO agrees with the proposed requirement R2.7.4 by the SDT.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**	
Name:	Wesley O. Davis
Organization:	Alcoa Power Generating, Inc
Telephone:	(704)787-1392
E-mail:	Wesley.Davis@alcoa.com

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☒	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☐Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☐Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.

- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☐
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☐
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☐
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☒

Comment: NERC is revising the Transmission Planning Standards beginning with TPL-001. Alcoa agrees with NERC's approach to revising TPL-001 wherein NERC is consolidating duplicative Standards to promote consistent requirements of the planning process and thus improving reliability. Also, Alcoa agrees that new studies should not result in inadvertent negative impacts on the system especially when such studies have not taken into account the negative impact on an adjacent system.

However, Alcoa believes that the current draft of the TPL fails to address FERC Order 890's requirements of an open and transparent Planning Process. Such a process provides Market Participants an equal opportunity for consideration in the Planning Assessments for contingency impact on transmission availability. (See FERC Order 890 ¶¶ 140, 207, 212, 323, 327, 337). Alcoa also believes that the current draft of the TPL fails to address and incorporate FERC Order 890's new requirement that transmission providers coordinate "…ATC calculations with their neighboring systems."

For example, while Planning Assessments may indicate no NERC Compliance violations where the Table 1 and Table 2 Requirements are met, Market Participants are harmed and not provided protection from unequal treatment of their circumstance. This problem occurs when an analysis of a contingency event results in no IROL or SOL (all facilities remain within established ratings), but resultant transmission constraints cause reductions of ATC and subsequent market impact. As part of the System Planning Process, this is unacceptable, and, as a minimum, this type of situation must be included as a scenario reviewed in the required sensitivity analysis under the NERC TPL-001-1 Standard.

The impact of such practices by large transmission providers on the ATC of smaller transmission providers can be significant. For instance, small transmission providers similar to Alcoa that operate non base-load resources such as hydropower, peaking units or wind power can easily see their ATC's reduced when sensitivity analyses are not performed under TPL-001-1. Alcoa believes that such sensitivity analyses should be a requirement.

Alcoa believes that for consistency with the provisions of Order 890, NERC must re-visit not only the Planning Assessment implications on transmission availability but also couple this review with the revision of the NERC Modeling Data and Assessment Standards (MOD). Alcoa recommends that the MOD and TPL Standards be addressed in similar fashion to:

1) Incorporate the intent of Order 890 requirements of an "Open and transparent Regional Planning Process to provide non-discriminatory planning" for ALL Market Participants

2) Assure that the revised MOD and TPL Standards fully address implications of burdens on the Bulk Electric System (BES) related to transmission availability for contingencies in the Planning Process.

FERC Order 890 ¶ 523 - Coordinate planning with interconnected systems. In addition to preparing a system plan for its own control area on an open and nondiscriminatory basis, each Transmission Provider will be required to coordinate with interconnected systems to (1) share system plans to ensure that they are simultaneously feasible and otherwise use consistent assumptions and data and (2) identify system enhancements that could relieve congestion or integrate new resources. (Emphasis added).

3) Sensitivity Analysis should include the potential impact on transmission availability and/or reductions in ATC on adjacent systems. Where ATC on an interface is reduced for a single contingency (N-1 planning, mitigation options must be provided). (This may require a threshold level of ATC reduction where a percentage reduction would be specified as acceptable on the N-1 basis, and a greater reduction than that threshold would be considered a Standard's Violation).

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☐

Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☐

Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for	☐Agree.	

stability) above 300 kV	☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

[1] System adjustment can be manual or automatic

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☐ No ☐
Comment:

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**	
Name:	William J. Smith
Organization:	Allegheny Power
Telephone:	(724) 838-6552
E-mail:	wsmith1@alleghenypower.com

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☒Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.

- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: Scenario analysis should be based on the unique aspect of the particular Transmission zone. Transmission Planners should work to select the best scenarios related to the specific system and adequately describe the selection process..

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: Providing examples would be helpful but specifically stating the required thresholds are transmission system dependent. Providing some methodologies to follow may be prudent such as forecast levels like 90/10; 80/20; or 50/50.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: No sensistivity needed for long term assessment.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in

conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: It should be included if there are specific mandated or approved DSM programs in place during the study period.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: Study area should be at least two buses beyond deficiency and plan elements.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: There needs to be a clear definition developed for committed and proposed projects and those definitions need to be included in the definition section of the standard.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance

requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an

[1] System adjustment can be manual or automatic

assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Should not be limited

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency

outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: This could be permitted provided the run back will allow for the ability to prepare for the next operational contingency and not affect load.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: The use of these system should be limited and not used as a preferred solution and also be approved by a stringent review process through the RTO & RE.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: The system should remain stable, reliable, allow for operational preparation for the next contingency and failure of the RAS/SPS should not lead to a cascading event.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☒
Comment: General Comments:

1). We believe the 300kV cutoff should not be used. It should be based on the definition of a Backbone Facility. The 300kV and above standards should only apply to backbone facilities that are used to provide overall energy transfer and ties to other systems and not facilities that provide load serving purposes. Backbone facilites should be specifically defined and accepted as Backbone facilities through RTO and RE review and acceptance.

2). Planning Scenarios should be forced to include a market based scenario under the Planning Authority obligation which should include long range market projections for generation dispatch, significant energy price changes due to environmental issues or fuels, and market impact of large transmission reinforcements.

3). It should be noted in the process that additional planning resource additions (maybe as much as 30%) will be required to met these new study requirements since they are much more expansive than the existing requirements.

4). These standards could require substantial (millions) upgrades to the system to meet the proposed changes. These are primarily due to the 300kV and above standard revisions and the non-consequential load drop criteria adjustments.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)	
Name:	John Sullivan
Organization:	Ameren
Telephone:	(314) 554-3833
E-mail:	JSullivan@ameren.com

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment: Yes, we agree that the "base case" is a power flow model and is the starting point of the analysis. What we are concerned with are the assumptions that go into the development of the "base case". The season, time of day, load level, generation dispatch assumptions, facilities in service, and interchange assumptions (all based on best available data) are just a small subset of the issues that need to be addressed in the development of the base case. We have concerns that so-called "stressed cases" proposed in the standard for compliance testing may in reality be contingency cases, from which additional compliance performance testing would be required.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment: A better name for this would be "direct load loss". The definition should include load served by the faulted element but not directly connected to the faulted element.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Most planning events have a low probability of occurrence. It appears that the SDT is trying to make a distinction that these extreme events would have a lower probability of occurrence than planning events. Consideration should be given to adding the performance requirements with the definition.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.

Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: It is suggested that another definition be added for "operations planning horizon".**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment: A better name for this would be "indirect load loss".**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: We do not agree that the planning assessment should include asset conditions and age. The age of equipment, if it is well maintained, has little impact on reliability. If NERC wants a standard to deal with age and maintenance of equipment, then it should develop a separate standard for asset management and not overburden TPL-001-1 with such issues.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Consideration should be given to adding the performance requirements in the definition.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: It seems that the SDT is trying to divide the stability issues between plant (local) and system. As the system load representation and its damping characteristics affect both plant and system stability, it is difficult to separate plant versus system stability studies. The focus of the studies may be only slightly different, depending on the location, type, and duration of the fault conditions assumed.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: See comments above in the response to Q9. Specific inclusion of voltage (load) stability seems to be missing from the definition. Also, angular stability is mentioned only as part of the definition for System Stability Study and not Plant Stability Study. It would seem that this item would be part of both types of study.**	
Q11. **Year One:** The first year that a Transmission Planner is	☒Agree.

responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: For the purposes of compliance, we believe that the existing requirement R1 in Standard TPL-001-0 adequately defines the sensitivities that need to be covered in a valid assessment, and no additional clarification is necessary. Deterministic tests of a limited number of system conditions require the application of engineering judgement to evaluate the complex multi-variable problems involved in planning analyses. We all agree that performing contingency analyses on a single snapshot of expected system conditions is not adequate to plan the transmission system, but planning is not a cookbook exercise, and neither is an engineering assessment of planning activities demonstrating required system performance. Further, we believe that a test of incremental transfer capability determined from some of the sensitivity cases needs to be added to the standard and would go a long way to address how much margin exists in the transmission system to handle the unknown or previously undefined variables.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: There is no need to build a multitude of sensitivity cases to assess the reliability of the system. The sensitivity issues should be handled on an individual system basis by the local transmission planners as applicable to the study system. Conditions that are considered as "stressed" for one area may require all facilities to be in service in another area. Powerflow cases utilizing a number of the items listed under R2.1.3 or R2.4.3 could be produced for in-house study work, but such work should not be required as part of standards compliance. The standard should not be dictating what types of sensitivities should be investigated or considered for all parts of the transmission system.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒

Comment: The biggest problem with performing stability analysis is getting the stability cases to match up with the powerflow cases, and only a limited number of stability cases are developed each year. Further, for those systems that are planned in excess of the NERC Standards regarding stability (3-L-G or 2-L-G vs. 1-L-G as in the Standard), there are no benefits to performing additional sensitivity studies to demonstrate compliance with this standard.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: There are more unknowns in the longer-term studies than in the near-term studies, which would indicate that more sensitivity studies would need to be performed and not less. However, it is more reasonable to suggest that if near-term sensitivity studies show a problem in a particular part of the system, then similar sensitivity studies need to be performed in the longer-term analyses.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or

Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☒

Comment: If DSM can be implemented in the required operating time, we have no objections to using DSM as the planned mitigation to relieve overloads or low system voltages for multiple contingency conditions, but not as a long-term solution for single contingency conditions. However, from our experience, we believe that developing enough DSM in the required time at specific locations in the system will be difficult, and that plain load-shedding would be required to supplement the DSM to achieve the desired performance.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒

Comment: This proposed requirement is unnecessary and a waste of time. Keep in mind this is a planning assessment and not a facilities study. Further, such a requirement implies a distrust of the transmission planners to develop valid corrective action plans to meet the requirements of the TPL standard.

For more complex system facility additions, it would be inconceivable that a Transmission Planner or Owner or Planning Coordinator would proceed without performing powerflow simulations to determine the efficacy of the system addition. But these studies would be perfromed over time considering the best available information and latest standards performance requirements.

The majority of transmission projects consist of the upgrading of terminal equipment or conductor on one or more branches. The only significant change that such upgrade work would produce in a powerflow model would be that the branch ratings would change. It is not necessary to rerun powerflow simulations for such cases, as it can be determined by inspection whether the upgrade work would be sufficient to move the facility rating above the expected normal or contingency flow.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒

Comment: We understand that there are differences between committed and proposed projects in an RTO environment where there is cost sharing for facility upgrades. From a NERC Standards compliance perspective, however, we do not see a need to differentiate between proposed and committed projects in the corrective action plan, as long as either properly addresses the required performance issue. We are not sure why there is a need to develop or maintain information on committed projects. This tracking is not needed to meet the existing TPL standards. Compliance requirements should be kept separate from administrative data requests. What is the perceived need to track committed projects that has not been presented here? Is this another example of distrust for transmission owners to build the proper facilities to create a more robust system?

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒

Comment: As stated above, we are not sure why there is a need to develop or maintain information on committed projects. This tracking is not required in the existing TPL standards. As long as the revised corrective action plan meets the reliability performance requirements, what difference does it make if a committed project is cancelled or changed to a proposed project from a compliance perspective? We need to keep compliance requirements separate from administrative data requests or survey responses.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus	☒Agree.	No significant material change identified.

section (SLG for stability) above 300 kV	☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Load pockets supplied by a single EHV substation with only two supplies would not meet this proposed requirement, whereas the existing TPL-003-0 standard would allow the dropping of load for the multiple outage event. A significant material change to build new facilities would be needed to meet the new requirement.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	No opinion as we do not have any transformers with the low side voltages rated above 300 kV. Transmission owners with transformers meeting this requirement should be consulted to determine if a material change would be required.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	No opinion as we do not have any transformers with the low side voltages rated above 300 kV. Transmission owners with transformers meeting this requirement should be consulted to determine if a material change would be required.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☒

Comment: This part of the proposed standard language is confusing. From our perspective, the failure of any 300 kV or above non-bus-tie circuit breaker should not result in the non-consequential loss of load. Further, EHV circuit breakers failing as a result of internal faults are extremely rare, bus-ties or not. Also, it is not clear what would be considered a non-bus tie breaker for ring bus and breaker-and-a-half bus configurations. It would seem that performance requirements for EHV bus-tie breakers (and not non-bus-tie breakers) should be distinguished from other breakers.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: The loss of two or more elements at any EHV substation at time of peak would likely result in loss of non-consequential load. If the intent of the proposed standard is to encourage the development of ring bus or breaker-and-a-half bus arrangements at the EHV level, we would concur where it is physically possible and makes for good engineering practice. However, we must remind the SDT that there are some existing facilities that cannot be converted practically or economically from their present straight bus configuration because of physical limitations. A significant material change, potentially several million dollars per substation, would be required to retrofit facilities, where possible. It would appear that performance requirements for EHV bus-tie breakers (and not non-bus-tie breakers) should be distinguished from other breakers.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	The outage of any two generators should not result in any non-consequential loss of load.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	The outage of a generator and any other element should not result in any non-consequential loss of load.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	The outage of a generator and any other element should not result in any non-consequential loss of load.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	The outage of a generator and any other element should not result in any non-consequential loss of load.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒

[1] System adjustment can be manual or automatic

Comment: If the system cannot withstand the outage of the single element (AC or DC) without curtailment of the transfer, then the transaction should not be considered as firm.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☒
Comment: We understand the need to clarify the different requirements in the steady-state vs. the stability analyses. However, for each contingency category we expect to see both the steady-state requirements and the corresponding stability requirements in the same table. We believe that it would be better to recombine the steady-state and stability tables and present the information in a landscape format.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment: We appreciate the SDT concern for performing repeated plant stability studies without any change in plant/machine characteristics. However, as the system load representation and its damping characteristics affect both plant and system stability, it is difficult to separate plant versus system stability studies. On some systems in which load and generation are tightly coupled, the focus of plant or system stability studies may differ only slightly with the location and duration of applied fault events. As such, the scope and manner of conducting System Stability study work under Requirement R2.4. for such portions of the interconnected system is not clear. Differences between Plant Stability Studies and System Stability Studies need to be made more clear.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment: A good test of the robustness of the interconnected system is its ability to handle import plus heavy inrush conditions, such as might occur with loss of a large plant. While the probability of such random events would be very low, the possibility still exists that intentional sabotage could result in such an event.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load

model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☒
Comment: Dynamic studies of peak load conditions should include the effects of induction motors, and particularly in areas where traditional load models have indicated a problem. Unfortunately, there is a lack of data to support the amount and characteristics of the detailed induction load models in many areas. In addition to the consideration of the dynamic effects of induction motor loads, the effects of static capacitor banks installed at both distribution and transmission voltage levels would need to be considered as well. The industry would be looking to NERC for some guidance as to how this data should be developed and maintained for models in future years.

Note that meeting such a requirement would necessitate a significant increase in the dynamic data needed to represent the system. Also, maintenance of such load model data would need to be considered. Load characteristics valid for a near term model might not be valid for future years. Also, summer peak load, winter peak load, and off-peak load characteristics would differ.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: No adjustment of firm (network resource) generation should be allowed for the long-term mitigation of a single contingency. Allowing post-contingency shifts of firm generation as a long-term mitigation of a single contingency event is short-sighted and would not produce a robust system that is required to handle more than single contingency events. Redispatch of firm generation may be required in the near-term as an interim operating guide or procedure until the limiting transmission element can be uprated or other system reinforcement is in place. Generation redispatch should also be allowed to prepare for the next single contingency. For responding to multiple contingencies, redispatch of firm generation should be allowed in the mitigation plan provided that the redispatch can be accomplished in the required operating time and the contingency overloads are not overly severe (indicating possible cascading). Firm generation should also be tripped to quickly mitigate contingencies involving multiple generation outlet transmission circuits. Non-firm (energy only) generation can be tripped or redispatched for any contingency event as needed to keep facility loadings within ratings.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☒
Comment: The runback of firm generation should only be allowed as a valid interim operating procedure until a system reinforcement would be installed to uprate or unload the limiting facility. The use of the runback scheme should not be allowed as the long-term solution to a single contingency event. As mentioned above in the response to Q35, non-firm (energy only) generation should be tripped or redispatched for any contingency event as needed to keep facility loadings within ratings.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☒
Comment: No generation runbacks should be allowed as long-term solutions for single contingency conditions.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: Yes, but only as interim operating procedures until the limiting facilities can be uprated or unloaded. SPS or RAS should be allowed to trip non-firm (energy only) generation to keep facility loadings within ratings.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: SPS and RAS should be used only as interim operating procedures to mitigate single contingency events until the limiting facilities can be uprated or unloaded. SPS and RAS should be allowed to trip non-firm (energy only) generation as needed to keep facility loadings within ratings.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: RAS and SPS should be allowed only as an interim operating procedure to mitigate single contingency conditions or to mitigate multiple contingency events on a long-term basis. The RAS or SPS must be effective in mitigating the contingencies and can be implemented within the required operating time.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment: The proposed standard, as well as the existing standards, makes no distinction between firm (network resource) and non-firm (energy only) generation. The standard should clearly state that the standard does not apply to non-firm generation.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: Much of the language under R1 appears to be redundant with model data requirements as listed in Reliability Standard MOD-010 and MOD-011. Such information would typically be used to produce an annual series of powerflow cases. Instead of supplying such information in a piecemeal manner to the Planning Coordinator as a separate annual effort, the Planning Coordinator should make use of the most recent set of powerflow models. This requirement, as written, could cause a needless duplication of work effort.

It is not clear what is meant by 'stressed System conditions' in Requirement R1.2. Does this mean higher than predicted load, lower than expected reactive resources, or other meaning? It is also not clear what is covered by 'load models' in the same requirement.

It is not clear how expected transfers are to be modified in Requirement R2.1.3.2. Possibilities include higher or lower in the same transfer direction, turn transfer directions around so that importers become exporters, the inclusion of non-firm transfers that can be cut, or change import/export directions. There should be some basis for the sensitivity change.

It is not clear how planned transmission outages are to be modified in Requirement R2.1.3.7. Possibilities include modification of the outage duration, or modifications involving more or less facilities. Since outages are scheduled in the operations planning horizon, based on the best information available at the time of the outage request, it is questionable whether they should not be included in standards that apply to planning in years 1-5 or year 6-10 and beyond.

Requirement R2.2.1. should be deleted. Uncertainties involved with studies looking at system conditions out to ten years in the future would preclude the need to extend a Planning Assessment beyond the ten year period. Any corrective actions needed to resolve problems found during study of long-term system conditions could be noted in the Planning Assessment without the need to extend beyond ten years.

In Requirement R2.3, the scope of the study work involving the short circuit portion of the Planning Assessment is not clear. It is not clear whether the study work should be based on three-phase faults only, three-phase and single-phase faults, or whether classical representation or more a more detailed representation should be utilized.

We assume that Requirement R2.4.3.5 would require only known generation additions, retirements, or other dispatch scenarios, and that those performing the planning scenarios would not speculate on unkown generation additions and retirements.

A market structure change in Requirement R2.6.1 would not constitute a material change in an area with an abundance of low cost base load generation that was always on before the market change and would still be on after the market change.

Under Requirement R2.6.3., Plant and System Stability analyses are considered valid until material changes in the System invalidate previous study work. Here, material changes in the system include addition of a transmission line or generator. Addition of a transmission line or generator would only have an impact on stability of generators near the new facility installation. This is not clear from the wording of the standard, which would appear to require restudy of all generators if a transmission line or generator is added anywhere on the system.

What would be the duration of interim operating procedures in Requirement R2.7?

Requirement R.2.7.1.1. states that a project initiation date should be included in the Corrective Action Plan for each project, as well as an in-service date. A project initiation date may be of use to the particular project design engineering staff, but is of little use in planning the system. Keep in mind that this is a Planning Assessment and not a data request.

The wording of Requirements R3.2 and R4.2 appear to require taking all transmission elements as contingencies, plus modeling contingencies which would remove all elements automatically via System protection equipment. Based on comments from the SDT, the inclusion of all single elements in the set of contingencies to be considered is not intended as part of these requirements. Please verify this in writing.

The wording of Requirement R3.2.1., dealing with generator minimum voltage limitations, is vague with respect to what is required. It is not clear who would determine the minimum steady-state voltage limitations for all generators, and for what conditions. Note that it may be difficult to obtain some information from IPP generating facilities.

Requirement R3.2.2. appears redundant with requirement R1.2.1 of FAC-008-1, which deals with Facility Ratings. Relay load limits are one component already considered in establishing facility ratings.

Requirement R3.3.2.1., which deals with the amount and duration of Consequential Load loss, cannot be addressed adequately. Because an outage might be caused by a transitory event with quick restoration of the outaged facility, or be caused by extensive damage requiring lengthy repairs, there would be no single value for expected duration for any given outage event in the planning horizon. Therefore, this requirement should be removed from TPL-001-1.

Requirement R3.3.2.2, describing permissible actions following single contingency events to meet performance requrirements, should be removed from TPL-001-1. System adjustments following single contingencies should not be permitted to meet system performance requirements. For similar reasons, Requirement R3.5, describing generator adjustments permissible as responses to single and multiple contingencies, should be modified to remove the reference to single contingencies.

What additional single contingencies would there be that should be considered in Requirement R3.3.3?

Consequential generation loss needs to be considered in Requirement R3.6 for those generators directly connected (through transformation) to transmission lines.

Interconnection requirements establish that generators must have low-voltage ride through capability. It is not clear how is the transmission planner performing the studies would be able to consider this capability in Requirement R4.3.

In Requirement R6, there is no longer a requirement to send the Planning Assessment and Corrective Plan to the regional entities, but to the Reliability Coordinators instead. Why has this change been made? RTOs should not be involved in assessing compliance.

In reference to Table 1, bullet point #3, it is not clear how voltage instability, cascading outages, or uncontrolled islanding would be determined under steady state conditions.

Under Table 1, P1, cutting of firm transfers is not permitted as a response to a single contingency. However, it is not clear whether, in preparation for a subsequent contingency, reduction in firm transfers would be permitted. Reduction in firm transfers should be permissible in this instance.

In Table 1, for contingency categories P5 and P8, how would loss of a transmission circuit above 300 kV followed by loss of a transmission circuit below 300 kV be handled?

Under the Extreme Event Description section of Table 1, note that item 3e. is a duplicate of item 3c. One of these can be deleted. Also, for items 3d. and 3f. the notation regarding early shutdown of nuclear facilities for tornadoes is not realistic. The current state of the art of weather prediction does not permit adequate forecasting of tornadoes a day or more ahead of time which might be a cause for concern for a particular nuclear facility.

With respect to Table 2, contingency types P5 and P8, it would seem that events should include the same items as shown for contingency type P4.

In Table 2, for contingency types P1, P3, P4, P5, P8, and P9, clarification is needed as to whether distribution transformers (138-69 kV or 138-34.5 kV, for example) would be included in the events, or whether the transformers mentioned would be restricted to transmission transformers.

For the various stability scenarios, note that Consequential Load Loss would be a function of how System protection equipment is set up for particular scenarios. Delayed clearing time/Zone 2 clearing times could result in load dropped that would not have been dropped for events cleared in primary clearing time.

In Table 2, Note 1 ii., is it the intent of the drafting team to require dynamic model representation of relaying equipment?

General comments:

We are not sure that a wholesale replacement of the existing standards TPL-001-0 through TPL-004-0 is required. We agree that additional clarification is needed for some items, and particularly for the study assumptions that go into the development of models to be used for the performance testing, but we do not agree that the proposed replacement standard provides that necessary clarification. Further, we believe that the replacement standard relies too much on the accompanying tables. More text needs to be included in the standard regarding the system performance requirements.

There is a lot of subjectivity involved in developing the study assumptions that need to be considered in the sensitivity models for study. How can we be sure that one or more of the sensitivity requirements in R2.1.3 stated for consideration are of the same level of importance by both auditors and those performing the studies? We are interested to see what the measures for all the requirements of the standard will be when they are developed.

Additional planning standard requirements for the EHV system to meet all N-2 conditions without dropping some load will require significant material changes, where feasible. We do not believe that the significant additional costs required for compliance would produce tangible benefits and a corresponding significant improvement in system reliability. What is the justification for the separate treatment for the EHV (>300 kV) facilities? One obvious effect of such requirements is to create a bias against any straight bus configuration for facilities above 300 kV. As stated in response to Question 25, there are existing facilities which cannot be converted from their present configuration. For those facilities which could be upgraded, an implementation period of several years would be needed to meet such requirements.

Meeting the requirements of this standard should not be a full time job. There are many more planning activities that need to be performed other than simulation testing to demonstrate compliance. The existing TPL standards require a significant manpower effort to perform the required studies and develop the planning assessment and corrective action plan. We are concerned that the replacement standard, as proposed, will create an even greater burden on the transmission owners without a commensurate benefit to the system reliability.

It is not within NERC's or ERO's scope of responsibility to address load loss. The focus of the standard should be on the system capabilities and not how much local load is dropped for a substation outage in a defined service area. A few reports showing the resultant bus voltages and facility loadings on a percentage basis for all single and a the more severe multiple contingency events, including operator or automatic mitigation procedures, should be adequate to demonstrate compliance.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information

(Complete this page for comments from one organization or individual.)

Name:	Thad K. Ness
Organization:	AEP
Telephone:	614-716-2053
E-mail:	tkness@aep.com

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☒ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☒ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: **AEP**

Lead Contact: **Thad K. Ness**

Contact Organization: **AEP**

Contact Segment: **1,3,5,6**

Contact Telephone: **614-716-2053**

Contact E-mail: **tkness@aep.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
Takis Laios	AEP	**RFC**	1
John Riley	AEP	RFC	1
Rob O'Keefe	AEP	RFC	1
Navin Bahtt	AEP	RFC	1
Scott Rainbolt	AEP	SPP	1
Omar Hellalat	AEP	SPP	1
Roger Bentz	AEP	ERCOT	1
Vance Beauregard	AEP	ERCOT	1
Phil Cox	AEP	RFC, ERCOT, SPP	5,6

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the

rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment: Consider replacing"computer" with "model".**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment: Consider replacing "Consequential" with better wording (no specific suggestion to offer at this time).**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.

Q6. **Comment: Consider replacing "Non-Consequential" with better wording (no specific suggestion to offer at this time).**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☐Do not agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☒ No ☐
Comment: Consider requiring a minumum of two sensitivity cases.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: Consider requiring that the most severe sensitivity cases be included in the studies as determined by the entities conducting the studies.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment: We concur with the use of sensitivity studies, but object to the requirement on what sensitivities to include. The flexibility to determine if sensitivity studies are appropriate, and the flexibility to choose what parameters are appropriate to study for sensitivity should be left open. R2.4.3 as written is restrictive to certain sensitivities and should not be.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☒
Comment: Consider requiring the same sensitivity analysis that is conducted under the near-term studies.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2

will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: Consider requiring that problem contingencies be simulated on base case that models the lower load level that would result with the DSM implemented.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: Consider limiting study area to immediately adjacent systems.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☒
Comment: Consider adding clear definition of "proposed" and "committed" projects (definition may impact response to this question).

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	Consider adding clear definition of "system adjustments", including the amount of time permited to implement prior to the loss of the second facility.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	Consider adding clear definition of "system adjustments", including the amount of time permited to implement prior to the loss of the second facility.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	Consider adding clear definition of "system adjustments", including the amount of time permited to implement prior to the loss of the second facility.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: Consider adding clear definition of "bus tie breaker" and "non-bus tie breaker".

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment: Consider adding clear definition of "bus tie breaker" and "non-bus tie breaker".

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

[1] System adjustment can be manual or automatic

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment: Extreme Event #9 in Table 2 has 3-phase fault and loss of all generating units at a station. Was this left in by mistake? This type of scenario could conceivably lead to low interconnection frequency or cascading due to consequent transmission overloading or low voltage, and could be studied by dynamic simulation. There have been a number of just such generation loss events as this in the past.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: The statements of fact in the question may be true for some study areas, but not necessarily for all. Requiring this type of load representation when it might not be appropriate to the study is excessively burdensome. This is a judgment better left to those conducting the studies. The percentage of load to be so represented, the extent of the study area over which to apply induction machine representations, and the specific modeling parameters are all judgements just as important as whether or not to

include this type of representation. There is a limit as to how far a standard can replace engineering judgment and that limit is reached here.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: The existing TPL standards imply that generator tripping is not permissible in connection with Category B events in that footnote b does not mention it, whereas it is mentioned in connection with Category C events in footnote c. Generation is a system resource and should be protected against the more common single contingency transmission events. We agree with the status quo on this issue being maintained in the new standard, with the provision for regional variance in R3.6. The provision for manual and automatic runback in R3.5 is okay. We also agree with manual adjustments remaining acceptable in response to any contingencies in the new standard consistent with C3 in existing TPL-003.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: Question: Why would a runback scheme be needed to move from an emergency state to a normal state when that could be accomplished by regular redispatch?

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Ensure that the scheme is enabled to automatically runback for the problem conditions.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: As long as they are automatic.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Should be allowed as long as they have been approved by the applicable Regional Reliability Organization.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: They include redundancy and their failure does not result in cascading.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: (1) Consider clarifying system performance requirements that would be applicable during (a) the first two minutes after the system disturbance when slow-acting automatic system adjustments (such as the operation of motor-operated-air-break switches that are relayed to sectionalize the faulted segment of a multi-terminal circuit; the changing of taps on tap-changing-under-load transformers; the switching of capacitor banks; etc.) would not allowed to be considered, (b) the next three minutes (two to five minutes after the system disturbance) when these slow-acting automatic system adjustments would be allowed to be considered, (c) the next twenty-five minutes (five to thirty minutes after the system disturbance) when manual system

adjustments would be allowed to be considered, and (d) the time period beyond thirty minutes after the system disturbance when no system adjustments of any kind would be allowed to be considered.

(2) Consider clarifying which functional entity is expected to provide what information specified in this standard, especially in requirement 1.

(3) Consider clarifying the need for functional entities to provide competitive sensitive information such as planned outages.

(4)The system stability study documentation requirements R2.4 and R4.5 do not specify a level on the scope of studies or indicate the extent of coverage across a system required for acceptability. A reasonable scope of such studies might include studies of a system nature in association with dynamic devices, or voltage collapse or cascading scenarios, but what else would be required? Or, how much more stability study documentation beyond what is necessary to comply with TPL-001 through 004 would be required? Specific comments regarding R2.4 are as follows: what does "address" all five years mean? How much of the system do you need to study (for example, do you need to apply faults at every bus)? Again, you wouldn't know how much studying needs to be done before this requirement is satisfied. In R2.4.1 and R2.4.2, depending upon the study at hand, some other load condition such as shoulder peak may be more appropriate. Why should you be required to do peak and off-peak cases in such an instance? In R2.4.3 you are forced into doing at least one of the sensitivity studies listed (i.e., "to reflect one or more of the following conditions..."). Is this intentional? Depending upon the study at hand, none of these may be worthwhile doing, and there may be some other parameter that would be better looked at for sensitivity purposes. Existing TPL-001 through 004, Table 1, Category C3 requires any combination of generator, transmission line, transformer, or HVDC pole block in succession. The new standard excludes several of these combinations from being required in P4, P5, P8 and P9. Is this an intentional exclusion? If so, why? The standard should state explicitly that existing generation does not need to be studied unless R2.5.1 or R2.5.2 apply.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **[Due Date in bold]**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**	
Name:	Nick Henery and Allen Mosher
Organization:	American Public Power Association
Telephone:	202-467-2985/2944
E-mail:	nhenery@appanet.org amosher@appanet.org

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☒	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☒ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. The SDT has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the SDT are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890 and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The SDT did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. The SDT organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The SDT determined that the requirements and analysis for Steady State are different from those for stability. As such, the SDT separated the analysis requirements and created two performance requirement tables.

The SDT recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The SDT has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The SDT has not addressed Measures, Risk Factors, Violation Severity Factors or Time Horizons at this time. These will be addressed when the SDT has better defined the requirements of the standard.

For questions where you agree with the SDT, please state that you agree and if available, please provide supporting documentation. If you disagree with the SDT, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you

believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the SDT would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the SDT is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: This should not be a defined term in the Glossary, instead there should be a Standard written that provides the industry with the requirements for completing a Base Case Study. This is the first step in completing the Transmission Studies required in TPL-001. There is no guarantee that the rules used by the transmission planners for the base case studies are done in a reliable manner. The Standard needs to be expanded to insure oversight by the compliance monitors to ensure that the base case is sound from a reliability perspective. Also, both reliability and transparency require that the results of the base case study along with the assumptions used to develop the study must be shared with responsible entities within contiguous areas of the BES, not just with contiguous Planning Coordinators and Transmission Planners. To insure consistent results, the Standard should require that a properly conducted Base Case Study be based on agreed rules for conducting such studies within each interconnection and use of consistent data/assumptions by other entities in the region; otherwise, the results of each PC's and TP's planning horizon studies and the operation planning studies will be brought into question.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment: This definition will help define what cascading outage is. There is**	

confusion in the industry and FERC as to "what is a cascading outage." The planning process needs to address this confusion and define exactly what a cascading outage consists. Some want a cascading outage to be when loads beyond the primary or secondary protection equipment are dropped.	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: The definition is needed; however, this term is dependent on a clear definition of Planning Events, which does not exist.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment: This definition is needed to eliminate the confusion that exists in the industry.**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers Years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: This definition is needed to eliminate the confusion that exists in the industry.**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: This definition should go beyond just saying "Load loss other than Consequential Load Loss." Recommend adding the following: " . . . including Load Loss that occurs through planned manual (Transmission Operator, Distribution Provider, and so on) operation or planned automatic operation of load shedding equipment such as under-frequency load shedding devices or Special Protection Systems."**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. Comment: This is too general. Just about any kind of review will qualify as a Planning Assessment. Suggested definition: "Documented evaluation of future Bulk Electric System needs by the use of performance studies such as NERC Steady State Transmission Studies or Plant Stability Studies conducted in accordance with the NERC Reliability Standards."	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: What are "performance requirements?" This is too general a statement to be of value for writing specific standards.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Insert "electric generating" prior to "plant" for clarity. It is unclear as to the intent of this statement. The Standard should require the Transmission Planner to consider contingencies in the vicinity of a particular electric generation plant. However,**	

the ultimate goal of the "Stability Study" is to determine the stability of the BES and not just the "electric generation plant." It is recommended that this be rewritten to make clear the intent of this statement.	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment: This is a very clear definition that can be used in Standards. The author did a good job of using defined terms in this definition.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits **their** annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: There is a term in the Glossary that is "Operation Plan;" however, there is not a term defining Operations Planning. It is recommended that the SDT drop the last sentence and define the term Operations Planning for the Glossary. Change "their" to "its."**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions", FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The SDT has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity (ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The term Base Case should not be used in this manner. The conditions of the Base Case Study should be in a Standard to insure that all sensitivity cases are covered.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☒ No ☐

Comment: The Standard should indicate a list that says "the list will include but not be limited to:" and then list the minimum necessary to adequately cover the changes in the study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐

Comment: This is absolutely necessary; it will help with the operational planning that will be needed next. In addition, it will help to determine the amount of study uncertainty that the Transmission Planner believes will be in the plan. This is very important for the Year One.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year 6 and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: The sensitivity study of year 6 and beyond is of little value. The uncertainty (standard deviations) in the input assumptions used to complete the studies for 6 years and longer are so large it would not provide useful answers to make sound decisions regarding the need to build, remove, or improve BES facilities.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If Yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: This is a conditional Yes. The Resource Planner or Transmission Planner must provide assurance that the specific "Demand" reduction that is incorporated into the scenario analyses will actually be reduced through either customer action or direct load shedding by the Balancing Authority. This type of controllable "Demand" does exist, but it is rare that planners and operators actually have such resources in their portfolios to help with System Deficiencies.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐

Comment: This is necessary to insure the planners did not accidentally take the system and the future operation of the system from the frying pan into the fire.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐

Comment: While it is good to know the difference, it should be made clear in the Standard that if a project is listed as committed, it may be changed the next year to proposed project. Definitions for "committed" and "proposed" are needed to ensure consistent data/assumptions within each region.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐

Comment: **It may be necessary, as a band-aid-type substitute, to replace a committed project with a Remedial Action Scheme (RAS)/Special Protection Systems in lieu of new facilities. Whatever the revised plan, it must be shown to meet the performance requirements.**

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable BES that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the SDT attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The SDT is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the SDT to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL Standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	**Note to APPA members – Please examine closely and give us specific comments on Q20 – Q29. If you disagree we need to know.**
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by	☒Agree. ☐Do not agree.	

loss of another Transmission circuit		
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards - P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

[1] System adjustment can be manual or automatic

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐

Comment: This has been needed for some time.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐

Comment: This is a conditional Yes. If the plant design was such that a fault at the plant could remove all units, then all units should be considered. However, if the plant design is such that the likelihood of all plants going down at one time is improbable, then the SDT's approach is very reliable.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐

Comment: The SDT is correct to include the effects of induction motors in simulating the loads. Voltage issues are and will continue to become more critical in the operation of the BES as time goes by. It will be a big help to planners and operators to know the impacts of such loads.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: I do not understand the question. Is this dealing with voltage adjustment or power adjustment?

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control.

The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: **However, it should be pointed out that RAS are band-aid solutions to building needed BES infrastructure. Experience has shown that an interconnection can have so many RAS that one RAS will counter another RAS designed for another problem in the interconnection. This problem requires additional study by a NERC task force.**

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐

Comment: **Care must be taken to insure runbacks of one event will not cancel the effects of other runback plans in the same interconnections.**

The SDT has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐

Comment: **As the SDT has said under certain situations.**

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: **See Question 36.**

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: **Maintain system stability and prevent the loss of load.**

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: **The WECC will probably have a couple.**

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: **The Standards are a great start in getting a set of requirements in place that will provide a planning methodology that will be transparent to the Functional entities in the interconnections and will produce results that will permit reliable planning and operations of the BES.**

Requirement 5 is a start at attempting to share the results of the planning studies with the correct entities. However, because this is such an important part of reliable planning, this requirement should be rewritten to be much more definitive and comprehensive. It is recommended the SDT review the FAC-014 Standard where this Standard deals with who is to receive the methodology for calculating SOLs. The SDT needs to insure that the Transmission Planners and Planning Coordinators share their Near-Term Planning Horizon Studies with the Transmission Operators (Operation Planners) and the appropriate Regional Entity Planning Committees and Operating Committees.

It is also recommended that the SDT remove all Requirements that are subjective and cannot be measured. For example, who must the Transmission Planner share information

with? Requirement R5.2 states that information must be shared with Transmission Planners of neighboring impacted areas. A Compliance Monitor cannot determine if a neighbor is being impacted. In fact, from an enforcement perspective, if the involved parties must go before a Judge, who will determine if someone is impacted or not?

In addition, the assumptions the Transmission Planners and Planning Coordinators use to conduct the Studies are not required to be shared or posted. As an example, in some parts of the BES Transmission Planners and Planning Coordinators use Flowgate Methodology to study the BES, while others use Rated System Paths, and still others use Area Interchange (Network Methodology).

This standard needs to be modified to respond to several requests from Order 890 and Order 693. These Orders request that through the Standards, information be made available, posted, and shared with the appropriate reliability functions. This information includes the results of Planning Horizon Studies, Operating Horizon Studies, and eventually the determination of Available Transfer Capabilities. This information also includes, but is not necessarily limited to: how do the planners treat the "counter flows" in their studies, what are the generation and transmission planned outage schedules used in the planning studies, how are Network Loads and Network Facilities treated in planning studies; and how do the planners treat Grandfathered Transmission and Grandfathered Power and Energy Contracts in the planning studies?

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Baj Agrawal	
Organization:	Arizona Public Service Co.	
Telephone:	602-371-6386	
E-mail:	bajarang.agrawal@aps.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ ERCOT	☒	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs and ISOs
☐ MRO	☒	3 — Load-serving Entities
☐ NPCC	☐	4 — Transmission-dependent Utilities
☐ RFC	☒	5 — Electric Generators
☐ SERC	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ SPP	☐	7 — Large Electricity End Users
☒ WECC	☐	8 — Small Electricity End Users
☐ NA – Not Applicable	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	**Additional Member Organization**	**Region***	**Segment***

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☐Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☐Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.

- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☐
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☐
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☐
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☐
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to “raise the bar.” Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment:

[1] System adjustment can be manual or automatic

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment: R 2.5.1 and R 4.6 require plant stability studies for all generators greater than 20 MVA for changes in excitation system or PSS addition. Generally plant stability is a problem only for large plants with large generators. Changes in the excitation system of a small generator or PSS addition does not significantly impact the plant stability. In fact, in most cases it improves the plant stability. When an excitation system or a PSS is commissioned in the field, part of the commissioning tests ensure that turbine-generator is stable and that the performance of the excitation system and PSS are acceptable. If an excitation system change or PSS addition is causing a plant stability problem in simulation, it is generally a data issue and can be best handled in MOD standards. Requiring stability studies to be redone does not in any way contribute to the system reliability. There are hundreds of old generators in the US which are going through excitation system retrofits in a given year. Requiring a stability study for each change would add additional study burden without any value to the system. This is unnecessary work with little consequence on the system performance or reliability.

Note: We have additional comments on these standards but they have been covered by comments from WECC. We fully support all of those comments.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

<table>
<tr><th colspan="3">Individual Commenter Information
(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td colspan="3">Name:</td></tr>
<tr><td colspan="3">Organization:</td></tr>
<tr><td colspan="3">Telephone:</td></tr>
<tr><td colspan="3">E-mail:</td></tr>
<tr><td>NERC Region (check all Regions in which your company operates)</td><td></td><td>Registered Ballot Body Segment (check all industry segments in which your company is registered)</td></tr>
<tr><td rowspan="10">☐ ERCOT
☐ FRCC
☐ MRO
☐ NPCC
☐ RFC
☐ SERC
☐ SPP
☐ WECC
☐ NA – Not Applicable</td><td>☐</td><td>1 — Transmission Owners</td></tr>
<tr><td>☐</td><td>2 — RTOs and ISOs</td></tr>
<tr><td>☐</td><td>3 — Load-serving Entities</td></tr>
<tr><td>☐</td><td>4 — Transmission-dependent Utilities</td></tr>
<tr><td>☐</td><td>5 — Electric Generators</td></tr>
<tr><td>☐</td><td>6 — Electricity Brokers, Aggregators, and Marketers</td></tr>
<tr><td>☐</td><td>7 — Large Electricity End Users</td></tr>
<tr><td>☐</td><td>8 — Small Electricity End Users</td></tr>
<tr><td>☐</td><td>9 — Federal, State, Provincial Regulatory or other Government Entities</td></tr>
<tr><td>☐</td><td>10 — Regional Reliability Organizations and Regional Entities</td></tr>
</table>

Group Comments (Complete this page if comments are from a group.)			
Group Name:	**Boneville Power Administration**		
Lead Contact:	**Chuck Matthews**		
Contact Organization:	**Transmission Planning**		
Contact Segment:	**Transmission Owners**		
Contact Telephone:	**360-418-8414**		
Contact E-mail:	**cematthews@bpa.gov**		
Additional Member Name	**Additional Member Organization**	**Region***	**Segment***
Berhanu Tesema	BPA, Transmission Planning	**WECC**	1
Kendall Rydell	BPA, Transmission Planning	WECC	1
Kyle Kohne	BPA, Transmission Planning	WECC	1
Melvin Rodrigues	BPA, Transmission Planning	WECC	1

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☒Do not agree.
Q1. **Comment: Support comments submitted by WECC.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☒Do not agree.
Q2. **Comment: Support comments submitted by WECC. The definition needs to consider loads that are tripped sympathetically that may not be directly connected to the element that is removed from service for fault clearing.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☒Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: Support comments submitted by WECC.**	

Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☒Do not agree.
Q7. **Comment: Support comments submitted by WECC.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Support comments submitted by WECC. Plant Stability is a subset of System Stability.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.

- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: Support comments submitted by WECC. Required sensitivities are different for different areas of the system and for the conditions being studied. The TP or PA are the most familiar with the system and would be the best one's to determine the required sensitivities.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: Support comments submitted by WECC.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☒
Comment: Support comments submitted by WECC.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or

Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☒
Comment: Support comments submitted by WECC. There is a concern with using DSM as a corrective action if it is not directly controlled by the utility and the benefits do not materialize as planned.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒
Comment: Support comments submitted by WECC.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: Support comments submitted by WECC. Also, one reason not to differentiate between committed and proposed projects is that regardless of whether a project is committed or not in a future case, the committment to implement a Corrective Action Plan becomes mandatory as time moves closer to the need date due to required system performance.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: See response to Q18.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	Support comments submitted by WECC.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Support comments submitted by WECC.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Support comments submitted by WECC.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	Support comments submitted by WECC.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: Support comments submitted by WECC. The probability of loss of a breaker due to an internal fault is low and does not warrent precluding loss of load for this event.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: Support comments submitted by WECC.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

[1] System adjustment can be manual or automatic

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☒
Comment: Support comments submitted by WECC.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☒
Comment: Support comments sent by WECC. There is a link between transient stability and steady state performance for a given event since they model serial time frames for the event.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: Support comments sent by WECC.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Support comments sent by WECC..

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☒
Comment: Support comments sent by WECC.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Support comments sent by WECC.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Support comments sent by WECC.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Support comments sent by WECC.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: Support comments sent by WECC.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: Support comments sent by WECC.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☒ No ☐
Comment: Support comments sent by WECC.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: Support comments sent by WECC. In addition,BPA has the following comments:

1. R2.3.1 - The way the requirement is written sounds like the short circuit study should be run after changes are made to the BES. The study needs to be done sufficiently in advance to allow for needed equipment replacements as a result of the study. Also, "current" in the first senetence should be changed because it is confusing whether it refers to "present" or "amps".

2. There needs to be better definition what is meant by "bus tie breaker". It is assumed this includes both bus tie breakers between a main and auxiliary bus, as well as bus sectionalizing breakers between two main bus sections.

3. In general the table seems unnecessarily complex. It would appear to make more sense to group events by performance as done in the previous Table 1. Also, in general the resulting events for the element contingencies in the table should be compared and like events grouped together since they would be are modeled the same and show the same performance in powerflow studies.

5. P9.1 - It is recommended to exclude multiple circuits sharing a common structure for no more than three miles, rather than one mile. Our analysis shows river crossing systems can be up to three miles and it is impractical to plan for common corridor outages of up to this distance.

6. Planning event P9.6 is the same as P8.3 with the only difference being the restoration time.

7. Regarding extreme event descriptions:
- Item 3.a is not a Transmission Planning, but is relevent for Resource Adequacy.

- Item 3.b is an operational issue not relevent to Transmission Planning. Successful cyber attack would need to be defined. Also, how would the consequences of a successful cyber attack be predicted?
- Regarding item 3.c, generation capabilities should already be modeled in base cases within the planning horizon.
- Items 3.d through 3.f are not relevent to Transmission Planning. These are Resource Adequacy issues within a short term operational horizon.
- Items 3.e and 3.f appear redundant to items 3.c and 3.d.
- Item 3.g is not really a planning issue. The system should be designed to meet required performance for selected contingencies regardless of age or maintenance pratices.
- In general, the extreme events layed out in the previous Table 1 is a much more practical approach to planning the transmission system.

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	David Albers	
Organization:	Brazos Electric Cooperative	
Telephone:	254-750-6358	
E-mail:	dalbers@brazoselectric.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☒ ERCOT	☒	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs and ISOs
☐ MRO	☐	3 — Load-serving Entities
☐ NPCC	☐	4 — Transmission-dependent Utilities
☐ RFC	☐	5 — Electric Generators
☐ SERC	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ SPP	☐	7 — Large Electricity End Users
☐ WECC	☐	8 — Small Electricity End Users
☐ NA – Not Applicable	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☒Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment: Some discussion of what 'documented' means is needed each time it is mentioned. Is this some form of written report at all times or are 'saved' cases with contingency analysis sufficient at certain times or is it just a means to show that an 'assessment' was performed in some fashion.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment: Planners do not 'submit' their studies to ERCOT for evaluation or other. Certain projects are submitted to the group for review and comment but not all studies are submitted as normal pratice in all cases. It may be better to use 'create their base cases' or simply 'performs their annual studies' instead of 'submit their annual studies'**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the

rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: More descretion should be allowed by the TO or planner in deciding the number of cases.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: Again, descretion should be allowed by the TO when selecting the criteria.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: Longer term studies should be performed in the broadest sense, the cases are difficult to create accurately and a greater range of sensitivities do not improve the results.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒

Comment: If DSM is not viable due to market failings, then its inclusion in any CAPs provides an inaccurate soltion to achieve the required system performance.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐

Comment: It is difficult to understand what is meant by 'retested'. The evaluation of a CAP includes testing the recommended option to see how it performs and to insure that it does not create other problems. We assume this is what is meant by retested. In our evaluation we insure that it does not negatively impact all other facilities in the BES and if so what extent and if it is managable. We do not always create a separate 'study area' each time for each system improvement.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒

Comment: What is the difference? We assume committed means you have begun work on the project and can no longer stop. It would seem this would need to be defined more clearly and it is probably different for each project or entity. Why is this differentiation even needed?

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒

Comment: This seems like more documention is needed however if the new CAP analysis will suffice for documentation regarding removal of the 'committed project' then this is acceptable. However, that kind of makes having such a thing as a 'committed project' fairly useless if you can change it. This appears to just be more unnecessary documention.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to

clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	need a definition of generator. The entire train, largest unit at a site or other.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	need definition of system adjustment
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	see above

[1] System adjustment can be manual or automatic

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: However, acquiring load data may be difficult if not impossible and would require increased manpower. A more reasonable approach is to vary the load data to see the effects instead of wasting effort on load surveys.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Can be including in a RAP or SPS with a long term CAP.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Taken directly from the ERCOT operating Guides for RAPs and SPSs:
Any RAP must meet the following requirements:
a. Coordinated and approved with the owners and operators of facilities included in the RAP.
b. Use is limited to the time required to construct replacement Transmission Facilities. However, the RAP will remain in effect, if replacement Transmission Facilities have been determined by the Control Area Authority to be impractical.
c. Complies with all applicable ERCOT and NERC requirements.
d. ERCOT develops and posts a methodology to include the RAP in the Total Transfer Capability (TTC) calculations, if appropriate.
e. Clearly defines and documents operator actions.
f. Includes the option for the transmission operator to override the procedures if the RAP will not improve system reliability.
g. Operators must be trained in RAP implementation.
For SPSs
13. Special Protection Systems (SPS) are protective relay systems designed to detect abnormal ERCOT System conditions and take pre-planned corrective action (other than the isolation of faulted elements) to provide acceptable ERCOT System performance. SPS actions include among others, changes in demand, generation, or system configuration to maintain system stability, acceptable voltages, or acceptable Facility loadings. An SPS does not include underfrequency or undervoltage load shedding. A Type 1 SPS is any SPS that has wide-area impact and specifically includes any SPS that a) is designed to alter generation output or otherwise constrain generation or imports over DC Ties, or b) is designed to open 345 kV transmission lines or other lines that interconnect TDSPs and impact transfer limits. Any SPS that has only local-area impact and involves only the Facilities of the owner-TDSP is a Type 2 SPS. The determination of whether an SPS is Type 1 or Type 2 will be made by ERCOT upon receipt of a description of the SPS from the SPS owner. Any SPS, whether Type 1 or Type 2, shall meet all requirements of NERC Standards relating to SPSs, and shall additionally meet the following ERCOT requirements:

- The SPS owner shall coordinate design and implementation of the SPS with the owners and operators of Facilities included in the SPS, including but not limited to Generation Resources and HVDC ties.
- The SPS shall be automatically armed when appropriate.
- The SPS shall not operate unnecessarily. To avoid unnecessary SPS operation, the SPS owner may provide a real-time status indication to the owner of any Generation Resource controlled by the SPS to show when the flow on one or more of the SPS's monitored facilities exceeds 90% of the flow necessary to arm the SPS. The cost necessary to provide such status indication shall be allocated as agreed by the SPS owner and the Generation Resource owner.
- The status indication of any automatic or manual arming of the SPS shall be provided as SCADA alarm inputs to the owners of any facility(ies) controlled by the SPS..
- When a Transmission Operator (TO) removes a SPS from service, the TO shall immediately notify ERCOT operations. ERCOT shall modify its reliability constraints to recognize the unavailability of the SPS and notify the Market. When a SPS is returned to service, the TO shall immediately notify ERCOT operations. ERCOT shall modify its reliability constraints to recognize the availability of the SPS.

14. The owner(s) of an existing, modified, or proposed SPS shall submit documentation of the SPS to ERCOT for review and compilation into an ERCOT SPS database. The documentation shall detail the design, operation, functional testing, and coordination of the SPS with other protection and control systems.

- ERCOT shall conduct a review of each proposed SPS and each proposed modification to an existing SPS. Additionally, it shall conduct a review of each existing SPS every five years, or sooner as required by changes in system conditions. Each review shall proceed according to a process and timetable documented in ERCOT Procedures and posted on the ERCOT website.
- For a proposed Type 1 SPS, the review must be completed before the SPS is placed in service, unless ERCOT specifically determines that exemption of the proposed SPS from the review completion requirement is warranted. The timing of placing the SPS into service must be coordinated with and approved by ERCOT. The implementation schedule must be confirmed through submission of a Service Request to ERCOT.
- For a proposed Type 2 SPS, the SPS may be placed into service before completion of the ERCOT review, with advanced prior notice to ERCOT in the form of a Service Request. The timing of placing the SPS into service must be coordinated with and approved by ERCOT. Existing SPSs that have already undergone at least one review shall remain in service during any subsequent review, and proposed modifications to existing SPSs may be implemented, upon notice to ERCOT, and approval of ERCOT before completion of the required ERCOT review.
- The process and schedule for placing an SPS into service must be consistent with documented ERCOT Procedures. The schedule must be coordinated among ERCOT and the owners of any facility(ies) controlled by the SPS, and shall provide sufficient time to perform any necessary testing prior to its being placed in service.
- An ERCOT SPS review shall verify that the SPS complies with ERCOT and NERC criteria and guides. The review shall evaluate and document the consequences of failure of a single component of the SPS, which would result in failure of the SPS to operate when required. The review shall also evaluate and document the consequences of misoperation, incorrect operation, or unintended operation of an SPS, when considered by itself, and without any other system contingency. If deficiencies are identified, a plan to correct the deficiencies shall be developed and implemented. The current review results shall be kept on file and supplied to NERC on request within thirty (30) days.
- As part of the ERCOT review and unless judged to be unnecessary by ERCOT, the appropriate ROS working groups such as the Steady State Working Group, the Dynamics Working Group, and/or the System Protection Working Group shall review the SPS and report any comments, questions, or issues to ERCOT for resolution. ERCOT may work with the owner(s) of facilities controlled by the SPS as necessary to address all issues.
- ERCOT shall develop a methodology to include the SPS in the Commercially Significant Constraint (CSC) limit calculations, if appropriate.
- ERCOT’s review shall provide an opportunity for and include consideration of comments submitted by Market Participants affected by the SPS.

15. SPS owners shall notify ERCOT of all SPS operations. Documentation of SPS failures or misoperations shall be provided to ERCOT using the Relay Misoperation Report located in Section 6 of these Operating Guides. ERCOT shall conduct an analysis of all SPS operations, misoperations, and failures. If deficiencies are identified, a plan to correct the deficiencies shall be developed and implemented.
16. For each SPS, the owner shall either identify a preferred exit strategy or explain why no exit strategy is needed to ERCOT. This shall take place according to a timetable documented in ERCOT Procedures and posted on the ERCOT website. Once an exit strategy is complete and a SPS is no longer needed, the owner of an existing SPS shall notify ERCOT, using a Service Request, whenever the SPS is to be permanently disabled, and shall do so according to a timetable coordinated with and approved by ERCOT and the owners of all facilities controlled by the SPS

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: see above

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: In R1.1.1. it appears the data that is being requested requires some amount of survey to determine the mix. This data would require a great deal of manpower and provide little more benefit than simply varying the data for comparison. However it does say in R1 upon request so does this allow the Planning Coordinator the descretion as needed on this type data?

R1.2, What is 'supporting rationale' and 'validated' mean? What are "stressed" System conditions? It appears (from 2.1.3) that stressed means various sensitivities.

R1.4, define 'long-term', generation outages are considered confidential information in ERCOT and thus are not available to all TOs, see next comment

R1.5 somewhere (perhaps in R1) the language should include "its respective portions of the data" or something to that effect meaning that a TO should not be held accountable for a GOs data. R1 appears to read that each entity shall provide the requested data. This seems to be intuitive BUT there are GOs that feel the data responsibility for the entire system belongs to the TOs and this leads to delays in getting accurate information if its uncertain as to who provides what data.

In R2 the language indicates the TP and PC shall each perform studies. There should be some clarity here. Also, it indicates that each shall assess "its portion of the BES". This needs to be clarified as well, obviously contingencies on other portions of the BES may cause issues within different portions. again, what constitutes documentation?

R2.1 it appears from the wording (shall "address" all five years) that the planning assessment must be done on all five years but 2.1.1 appears to state only 2 years are required. Please clarify.

R2.1.3 this seems to indicate that the studies mentioned in 2.1.1 and 2.1.2 should be "stressed" by the conditions listed below or just by one of them. We assume this means using only one is acceptable with proper documentation. Is that correct? Further, the sensitivities are ambiguous. How does one justify higher load levels or even know what they are without input from other TOs or the PC? How does one even guess at the other variables? what is meant by 'long lead time facility'? IF this only means for a TOs "portion of the BES" then it makes more sense but are these even valuable considering the wide range of data. The only variable that can be adjusted with any accuracy is the generation and ERCOT maintains the confidential data in this area. We assume R2.1 to mean you need to assess two peak summer cases, one off peak and then look at varying generation patterns on those cases. This appears to be the latitude given. Is this correct?

R2.2.1 are generation additions considered a "project"? If this means that a case must be created and assessed by all TOs for a known generation addition that is 12 years out, then this will lead to unnecessary studies. We assume this to mean, in the case of a generation addition, that the connecting TO should make an assessment once the PC considers this new addition to be valid for study. Is that correct?

R2.3 what is meant by "past studies" and how long must these be kept? Or is this at the TOs discretion?

R2.3.1 how does one know if the changes will result in increased fault currents until studies are done? This implies that studies SHALL be done for just about ANY change to the BES. There must be discretion allowed here. The word "shall" does not afford any discretion.

R2.4 the same comments for R2.1. apply here concerning years of study and defining 'stressed'. Additionally this type study seems to provide better results when done for the BES which would require input from all TOs thus a study based only on "its portion of the BES" would not have as much value unless you are referring to generation additions and localized studies.

R2.5.1 does not allow any discretion, for any and all all modifications, additions, etc…a study shall be performed. This is not needed in all cases.

R2.5.2 Wording such as "material changes" and "vicinity" are ambiguous terms without discretion being allowed the planner. Voltage level Line changes, amount of generation, something needs to be added to clarify.

R2.6.1 again, what are material changes? Topology changes and generation changes happen monthly, weekly. Are studies to be invalidated for each 'material change'?

R2.6.3 who determines if the study is no longer valid? The TO, PC or the agreement of both?

R2.7.1 what is a 'project initiation date' and why is this needed?

R2.7.2 Projects are added to cases after an analysis has been performed to see if the project is an acceptable alternative. In that analysis the project is 'retested' to see if it is effective. This is assume to be acceptable for the definition of 'retesting'.

R2.7.3 unsure what 'committed' means regarding projects nor understand the need to have this documented anywhere.

R3.2.2 what is 'relay loadability' and where would you note how it is supposed to be treated?

R3.3.1 how is this different than R3.1?

R3.3.2.1 why is there a need to know how much non-consequential load loss exists for each contingency and how can one predict the length of time this will last?

R3.3.2.2 Do we need to document the 'system adjustment' for each contingency?

R3.3.3 what is a severe impact and what is one that is less severe?

R3.4 what is the difference to 3.3.3? The definition given in the NERC Glossary from May of 2007 of Cascading Outage is still vague, it appears to allow the TP or PC the discretion to determine it based on studies. Is this the intent?

R3.5 what is the time limit for run-back?

R4.4 how can TPs identify what generation upgrades are needed (protection and control modifications)?

R4.5.2 whats the difference between this and 4.5.1?

R4.6 the generation levels could be too low for the studies to be useful, perhaps voltage levels should also be added or allow for TP/PC discretion.

R4.6.3 seems to allow some TP discretion in deciding which planning events are more severe but how does one know that without studies?

R5 this seems to have no direction for either party.

R6 is ambiguous

Table 1
terms such as voltage instability, cascading outage and uncontrolled islanding should be defined or allowed to be defined by the PC. If consequential load loss is allowed for all cases then why even mention it? Isn't this like saying if the line trips, it will be out of service? why would one want to document this amount, perhaps for some sort of ranking?
Planning events
what is a 'system adjustment'? if this means to manually redispatch the BES for each condition then these studies shown under P4 will take so long to complete that they will be invalid by the time they are done. In ERCOT, the economics of redispatch are not known to the TP thus this is done by the PC. an automatic computer simulated redispatch will possibly not have the same results. Define 'generator' for is this a single unit, the whole train, the largest unit or other?
For P6 events and above, if consequential load loss and non consequential are allowed, they why study these events? Do TPs plan and build transmission to eliminate the overloads for these events or just study them so that the results are known? Studying every possible event or combination does not make the studies better or provide a

higher insight to areas of concern. A number of the combinations have a low probability of occuring and performing the studies and analizing the results will be a manpower burden and provide no better clarity on needs of the system.

Table 2
The number of events to consider seems excessive although this is not our area of expertise. If each of these is to be run for each 'material change' in the BES then this list is excessive without more leeway or guidance provided.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Phil Park	
Organization:	BCTC (British Columbia Transmission Corporation)	
Telephone:	604 699 7340	
E-mail:	phil.park@bctc.com	

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☒ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☒	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: For the reasons discussed below, we do not agree with the proposed definition. To address our concerns and address the FERC staff concern regarding ambiguity, the proposed definition could be made acceptable to us by modifying it as follows:** **Load that is no longer served because it either (a) was supplied (wholly or partly) by an element(s) of a radial system or local network that was removed from service due to fault clearing action, was disconnected by controlled interruption to avoid overload of remaining elements of a radial system or local network, or protection or SPS/RAS mis-operation or (b) has dropped out or been tripped during a transient stability period, including an automatic reclosing period, due to a fault on the radial system or local network, including on branches not directly supplying the load.** **We also offer the following alternative:** **Resultant loss or controlled interruption of customers supplied by a radial system or local network, due to a fault on or loss of a facility in the radial system or local network.** **The definition proposed by the SDT removes the second sentence of footnote (b), as directed by FERC, and replaces the first sentence of footnote (b) with a new definition. We agree with the removal of the second sentence of footnote (b). However, we have a concern with this**	

definition replacing the first sentence of footnote (b). We believe that the existing first sentence is a more appropriate definition of consequential load loss and that the proposed definition is more stringent and will have unacceptable impacts on reliability and/or add transmission costs that cannot be justified.

The coining of the term "Consequential Load Loss" has been a significant improvement in terminology compared to our reference to footnote (b). However, FERC only used this phase descriptively and did not order NERC to reconsider what would be acceptable consequential load loss (i.e. revise the first sentence of footnote (b)). The definition appears to be based on an interpretation of the new term rather than defining what this term was coined to describe.

Order 693 requires that footnote (b) be clarified to not allow loss of firm load or firm transfers - i.e. delete the second sentence. Order 693 then refers to the remaining first sentence as consequential load loss. Order 693 does not address issues regarding whether this should further be restricted to only radial lines, not permitting load loss for outages on local networks. Nothing in the NOPR or the staff paper implies otherwise.

The staff paper discusses potential ambiguity regarding which single contingencies load interruption is permitted for. The definition attempts to address this by referring to "directly connected" load. However, this is now ambiguous as "directly connected" might be interpreted to mean only the facility that the load is physically connected to and excluding any upstream facility.

BCTC submits that the upstream facilities need to include both radial facilities and local networks. NERC has stated that looped configurations are key for reliable operation. We consider looped configurations and local networks to be the same thing. The proposed definition will make it more difficult to transition from a radial supply to a looped configuration. For radial loads connected by a single radial line, when the load exceeds the line capacity, the transmission owner has alternatives of upgrading the line, adding a second circuit, or converting to a local network by providing a loop from another supply. With the addition of a second circuit or conversion to local network, controlled load interruption may be necessary for loss of one circuit to avoid overload of the second line. Without the option of controlled load interruption, these alternatives will not provide N-1 capability for all loads they supply without addition of a third circuit. This will lead to a economic preference to upgrading of the existing circuit to meet criteria, thereby perpetuating the single radial line configuration. Other alternatives could include splitting the load between the lines or operating with one line out of service so that a single contingency does not overload the facilities remaining in service. However, the addition of a second circuit with controlled load interruption will provide a more reliable load serve than any of these alternatives, because under N-1 more load will remain continuously on line. We expect that the proposed definition will provide greater assurance that existing local networks with N-1 capability will continue to have N-1 capability. However, we have concluded that the definition will introduce an additional unacceptable barrier to transition

from N-0 to N-1 supply and that this barrier is not acceptable. We believe that this barrier would be a more significant issue for improving the reliability of supply to all customers than the current situation of permitting some controlled load interruption on local networks. **Another issue that arises if local networks are excluded is load response during transient periods. Customers can connect voltage sensitive loads, such as large motors, on long weak systems. During the transient stability period, voltages can dip to below the ride through capability of the load. The fault need not be on the circuit directly supplying the customer, but may be downstream or on another branch facility. Automatic reclosing is often employed to shorten restoration times, but with the consequence of worsening the transient period. Customers have options to install different types of motors, motor controls, local voltage support to mitigate impacts of transient voltage swings, or simply restart motors following the disturbance. If transmission systems are required to ensure no loss of load during transient stability periods for external faults, a first course of action may be to remove automatic reclosing, which will reduce reliability. Alternatively, customer load connections may be denied or additional transmission circuits may be required, which can be costly compared to the customer load options.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Alternative wording proposed:** **Events which have a low probability of occurrence and are typically more severe than Planning Events.** **Explanation: The primary consideration is the probability of occurrence. We do not exclude events simply because they are more severe.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: See comments on Consequential Load Loss. Propose the following definition to clarify situations for which NCLL is acceptable:** **Load loss other than Consequential Load Loss to avoid cascading, voltage**	

stability, or blackout of the BES. For example, load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage load shedding, under-frequency load shedding, or SPS/RAS.	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Need to insert the word "supported", as below, and further refine, to clarify that the Planning Assessment is not just studies, but includes evaluation of contingencies to be run, sensitivities to consider, etc.** **Documented evaluation of future BES needs, measures to mitigate adverse reliability impacts, and assessments of residual impacts, supported by the use of performance studies ....**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: One problem with this definition is that it assumes that the Transmission Planner submits annual studies. We need definitions for Operating Horizon and Planning Horizon. Then:** **Year One: The first year of the Planning Horizon.**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of

variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☒ No ☒
Comment: The number of sensitivity cases should be tied to the number of resource plans and range of possible load growth forecast.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: Should be tied to the data provided under R1.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☒
Comment: Long term needs to address sensitivities since it usually takes more than five years to contruct new transmission lines.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: DSM should be a load reduction.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐

Comment: The Assessment should state how the study area was determined, including input from adjacent Planning Coordinators. WECC has processes for coordination of planning information so that Planning Coordinators are informed of plans in other areas.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐

Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☒

Comment: We have a larger concern. If a project is Committed and is proceeding with construction, why would a transmission planner not consider this is in planning studies. Showing that a committed project is not needed and removing it from the plans, does not necessarily remove it from the future system. In addition to showing that the revised plan meets the performance requirements, the planner needs to include documentation to show that the Committed project has been cancelled.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	Do not agree based on SDT definition for Consequential and Non-Consequential Load Loss. Will agree subject to proposed revisions to definitions of Consequential and Non-Consequential Load loss.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Do not agree based on SDT definitions. Also do not agree for first outage being a forced outage. Will agree subject to above revisions to definitions of Consequential and Non-Consequential Load loss for the first outage being a planned outage but not a forced outage. To meet this requirement for forced outages, estimate that this change could cost $3 to 5 Billion.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	Same comments as for Q21. We do not foresee any cost due to this standard at this time because we do not have any transformers with low side voltage rating above 300 kV.

with low side voltage rating above 300 kV		
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	Same comments as for Q21/22. Furthermore, a double transformer loss forced outage has a very low probability as transformers are very reliable. A more practical approach would be to use single phase transfomers and provide a spare phase.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒

Comment: Do not agree due to definitions of Consequential and Non-Consequential Load Loss. Can agree subject to the proposed revised definitions to address loss of load during the transient stability period. System is already planned to meet this requirement based on the first sentence of footnote (b).

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: Do not agree due to definitions of Consequential and Non-Consequential Load Loss. Can agree subject to the proposed revised definitions to address loss of load during the transient stability period. System is already planned to meet this requirement based on the first sentence of footnote (b).

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	Do not agree due to the definition for Consequential Load Loss. Definition needs to include local networks for this contingency to be acceptable.
Q27. P4-2: Loss of a generator followed by a System adjustment followed	☐Agree. ☒Do not agree.	similar to Q26.

[1] System adjustment can be manual or automatic

by the loss of a monopolar DC line		
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	Similar to Q26.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Similar to Q26.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒

Comment: Disagree with this unless AC lines are treated the same. There should be no distinction between AC and DC lines.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☒

Comment: Disagree with the assumption that steady state and stability analysis are different and should be separated. There are only minor differences between the tables and the reasons are not apparent. The separate tables appears to be unnecessary and is confusing, especially the same contingency numbering for both tables. Any contingency that must be studied in the stability period should also be considered in the post transient steady state period. Request that the SDT provide an explanation of their assumption.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒

Comment: Plant stability is a Generator Interconnection study, addressed by FAC-001. By including this requirement in TPL, costs may be transferred. TPL-001 need not distinguish between system stability and plant stability. For Planning Assessments, these are the same thing. Plant stability arises when doing generator interconnection.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment: Stability should be treated the same as steady state. If there is a common mode event that could cause the loss of all generating units at a plant, all relevant simulations should be done. If a common mode contingency of all units at a generating plant is not relevant for stability, then it is not relevant as an extreme event for steady state either. However, operation with all units at a plant off line may be relevant as a sensitivity case for Planning Events. The Transmission Planner needs some lattitude to determine what needs to be considered under Extreme Events and the standards should not be overly perscriptive.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐

Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: No restrictions on adjustments that are practical and can be achieved within the timeframe required.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☒

Comment: We do not accept R3.5, which does not limit runback to contingencies based on thermal limits, only that Facility Ratings are not exceeded. If an SOL is based on voltage stability (which is often studied in the post disturbance steady state), Facility Ratings may not be exceeded but runback may not be fast enough to avoid voltage instability. Furthermore, runback for single contingencies should be subject to any conditions that might apply to generator tripping for single contingencies.. See response to Question 39.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☒

Comment: See our response to Question 36. In addition, since this runback is effectively a RAS/SPS with respect to protecting the transmission system from cascading, it must meet all the reliability requirements of a RAS.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐

Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: RAS should be permitted when the system performance conforms with the performance requirements laid out in the tables. Generator tripping should be permitted for single contingency events.

R3.6 proposes to limit generator tripping for single contingencies except for certain conditions which are not listed. Without knowing what these conditions might be, we find ourselves speculating on what might be proposed. On the 10 October 2007 conference call, it was suggested that there are concerns regarding generator reserves and loss of reactive capability. We have some observations regarding these concerns. With respect to reserves, some concerns would also apply to runback, since units on runback could not also be on AGC and could not be reallocated to AGC until the transmission contingency is returned to service. There was also a concern regarding tripping of steam units and the delay in bringing them back on line. This is a resource adequacy issue that should be addressed with the customer, not a transmission reliability issue. Regarding the loss of reactive capability, this would be addressed by the post mitigation plan studies to demonstrate that the reactive reserves meet the requirements, whatever they are determined to be. We would generally expect that the reduction in MW transfers would reduce the need for reactive support, so the new condition might not require the reactive support. Nevertheless, the post mitigation studies will address this. Therefore, we conclude that these concerns are not applicable to transmission planning standards.

BCTC plans and operates a transmission system that interconnects generation comprised of about 90% hydroelectric. Often the extreme generation patterns for which we consider generator tripping occur for a limited time period during the year at off peak. These would be during high runoff and/or light local load periods. For these conditions, there is typically plenty of other generation that can be used as reserves for generator tripping. BCTC currently strives to avoid use of RAS for N-1, especially on the 500 kV transmission system. However, for example, if avoiding generator tripping were to trigger the need for hundreds of km of 500 kV transmission line for an off peak operating condition or a low capacity factor or intermittent resource, we would likely consider RAS, especially for transmission radial to the generator. In the lower voltage systems we often have consequential loss of small generators and consider generator tripping for radial lines and local networks. In most cases, this generator loss is addressed through sensitivity studies and discussions with generator owners and transmission customers with respect to the costs they are willing to incur and what is required by Resource Planners to meet their planning criteria. Operating reserves requirements are also a consideration. Any loss of generation due to tripping or ramping that is less than the amount lost due to consequential loss should be acceptable without question.

In summary, we would be prepared to review and comment on a proposal from the SDT on limitations on generator tripping. BCTC suggests that the SDT list the limitations rather than the permitted conditions and that these limitations should also apply to generator ramping.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: See Q39. Also, WECC RAS Reliability requirements must be met for new systems.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: WECC may require a regional difference for generator tripping depending on the conditions imposed in R3.6.1. Other regional variances would not necessarily be in the context of regional difference as defined in the Standards Manual, but rather exceptions for long weak systems for which it is not economic to meet criteria applicable to tightly interconnected systems.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:

1. We have some questions of clarification for the Standards Drafting Team, that may resolve some of our concerns. (i) Is it the intention of NERC that the more stringent performance requirements in this standard would be applicable for determining System Operating Limits before Transmission Owners are able to implement Corrective Action Plans? The BCTC system is part of the western interconnection and BCTC is a member of WECC. WECC members apply a principle that Planning Standards are also applicable for determining System Operating Limits. If the answer to this question is "no", then BCTC may be able to support some aspects of raising the bar, with the understanding that SOLs would be determined based on the performance standards that the system is planned to. (ii) Has the Standards Drafting Team considered how Transmission Planners will address discrepancies between Corrective Action Plans for this standard and the reality of what can be constructed due to regulatory approvals, siting problems, financing issues, etc.? For example, is it the intention that Transmission Planners should continue to study Corrective Action Plans to meet an N-1-1 Planning Event (e.g. P5-1) without generator tripping when the practical situation is that we may be fortunate to be able to build to meet N-1 with some generator tripping? We are concerned that if we cannot meet the performance requirement for P5-1 due to delay or denial, continuing to assess Corrective Action Plans to meet P5-1 does not provide much useful information compared to planning to meet a doable target. Item 2 below provides a proposal to address this.

2. There is always the possibility that a regulator may deny funding for a Corrective Action Plan or approve funding for a Corrective Action Plan that does not fully meet the performance standards, a siting process may delay or block a Corrective Action Plan, or some other process may frustrate the ability follow through with a Corrective Action Plan to meet NERC performance standards. To avoid the need for a Transmission Planner to continue to study Corrective Action Plans that cannot be implemented, we suggest adding the following Requirement R2.7.6: The Planning Assessment is not required to include a Corrective Action Plan and address the subsequent requirements (of R2.7) in cases that (a) an applicable regulatory agency has ordered that a Corrective Action Plan is not to proceed or that an alternative Corrective Action Plan that does not meet the performance standards is to be implement or (b) the Transmission Planner has documented evidence indicating that such an outcome is likely to occur. Other Requirements for Five and Ten year Assessments may also be exempted depending on the regulatory order. The Planning Assessment will include evidence of the order.

3. R3.3.3, R3.4, R4.5.1, R4.5.2 - A rationale for the selected contingencies should be sufficient. It should not be necessary to explain why the remaining contingencies would produce a less severe result.

4. Table 2, P1 should include shunt devices.

5. A definition or reference to a definition for Firm Load and Firm Transfers is required. The present situation is that these terms are "defined" as those loads and transfers that can be supplied while meeting Category B requirements. In other words, the standards

define the terms. The commercial uses of firm and non-firm may not be applicable and they actually mean non-recallable and recallable service, not directly related to system performance, but incorporating aspects of reservation times.

6. Extreme Events of Tables 1 and 2 should not be subject to the same study requirements as Planning Events. Table 1 Extreme Events need not be studied for both the Near Term and Long Term Horizon (ref. R3.4, R3, R2.1 and R2.2) and for all five years of the Near-Term Horizon (ref R3.4, R3, R2.1). Table 2 Extreme Events should not be required for all five years of the Near-Term Transmission Planning Horizon (ref. R4 and R2.4). When conditions warrant, only a single assessment representing a selected reasonable plannning horizon should be required, and an update required only when past studies are no longer representative. We are concerned that many of the proposed Table 1 Extreme Events (Item 3. a, c, d, e, f) are resource adequacy issues (we also observe that c and e appear to be identical). Transmission Planning Assessments of these events should be initiated at the request of Resource Planners. It should not be necessary for Transmission Planners to initiate and maintain current studies of these Extreme Events. We suggest that Extreme Events be removed from R3 and R4 and addressed in a separate Requirement.

7. The Purpose of this standard should be restated as: Establish requirements for Planning Assessments, including Corrective Action Plans, to be conducted over range of forecast conditions based on system planning performance requirements. Explanation: This revised wording more accurately describes the content of the standard. The Requirements of this standard are to perform Studies and Assessments. The performance tables are referenced by the Requirements and are supporting to the Requirements, but are not a "capital R" Requirement.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Charles Cumpton	
Organization:	California ISO	
Telephone:	916-608-7367 or 916-608-1100	
E-mail:	fcumpton@caiso.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment: It is a fair description for an initial base case.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment: Agree with the definition**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Add specificity in this definition. Suggest the following wording: Outage of two or more elements from service with lower probability of occurrence than Planning Events**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment: Agree with the definition**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: Agree with the definition**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: Add Remedial Action Schemes (RAS) after "Systems"**	
Q7. **Planning Assessment:** Documented evaluation of future	☒Agree.

Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Do not agree.
Q7. **Comment: Agree with the definition**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Needs clarity. Suggest the following wording: Outage of power system elements such as shown in Tables 1 and 2 that need to be considered and simulated to assess Transmission System Performance**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Definition is not clear. Suggest the following wording: Study of an individual generating plant's capability to remain in synchronism and exhibit damping of the generating units' power oscillations for various contingencies in the vicinity of the plant**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: This definition is for a stable system. Study is performed to determine whether system is stable or not. Suggest the following wording: Study of the system or portions of the system to assess the system's performance in terms of angular stability, power oscillations and voltage limits during dynamic simulation**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: Suggest a shorter definition: Planning window beginning next calendar year**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The TP or PA is the best to determine the number and type of sensitivities that are more applicable to their system.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: Let the TP or PA decide the type of stressing needed for a particular case

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒

Comment: Although we concur with the sensitivity analysis but the TP should determine what sensitivities are more appropriate for their system. Sensitivities should not be scripted in the Standard.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: Agree. The Standard should state that sensitivity studies are not required but the TP or PA could use sensitivities if desired.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This

Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: We agree to include DSM among a mix of solutions to a system problem. However, the difficulty is that DSM is unpredictable when needed. Another issue is how much DSM is actually under the control of the Transmission Operator.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐

Comment: We agree that the system should be retested with the corrective measures to ensure that the defficiency has been cured and that there are no inadvertant negative impacts. Regarding Study Area, it is not a defined term, and it could vary depending on the size of the project or nature of the disturbance being evaluated.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒

Comment: The understanding about "committed" projects vary from TP to TP. Also projects that are proposed today become committed in the planning horizon. Similarly, committed projects drop out due to variety of reasons. In terms of system studies, both committed and proposed projects are modeled and evaluated in the same system. How do we distinguish between the two?

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐

Comment: We agree that committed projects should not be removed from the revised plan. These are supposed to be included in the planning studies which determine the system performance in the first place.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	Loss of bus section is Category C for which the current NERC criteria allows controlled loss of load. The NERC system has been designed with this criteria. To create a more stringent standard would require to build hundreds of miles of new transmission lines to bring the existing system to NERC compliance. What are the potential benefits of this stringent criteria? Also, what is the reasoning behind selecting 300 kV as a cut off level?
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	This event also falls under Category C for which the current NERC criteria allows controlled loss of load. Clear net benefits should be demonstrated to justify adapting to a new stringent criteria.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	This event also falls under Category C for which the current NERC criteria allows controlled loss of load. Clear net benefits should be demonstrated to justify adapting to a new stringent criteria.

with low side voltage rating above 300 kV		
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	This event also falls under Category C for which the current NERC criteria allows controlled loss of load. Clear net benefits should be demonstrated to justify adapting to a new stringent criteria.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: Same response as for Q21

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: Do not agree for loss of a bus, or loss of a stuck non-bus tie breaker for the reasons as in the response to Q21.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	Non consequential loss of load should not be permitted for this type of event. Loss of a generator has higher probability and longer duration than many other contingencies. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise has higher probability than other multiple contingency events.

[1] System adjustment can be manual or automatic

Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	Agree that non consequential loss of load should not be permitted due to higher probability of generator outage.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	Same reason as in Q26.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☐Do not agree.	Same reason as in Q26.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: In addition, the interruptible and other negotiated transactions should also be allowed.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment: Agree that the two analysis should be treated separately.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: Plant stability studies are a subset of system stability studies in which loss of a generator is already evaluated to meet performance requirements. In specific situations, sensitivity analysis can be done as deemed appropriate by the TP to address a particular system problem.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐

Comment: It will be cosistent with the performance requirements under Steady State conditions. Also, loss of entire generating station is possible for a variety of reasons such as, loss of all lines emanating from the station, loss of the gas pipeline feeding the plant, etc.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐

Comment: The requirement to include motor load should be extended to other load levels as appropriate.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Maunal such as tripping the generators, automatic such as AVR, excitation systems, stabilizer, and governor adjustments

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: Agree

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: 1. Run back of generation should not result in tripping of firm load, 2. Power flow should be within the applicable ratings, 3. Frequency should be within the allowable limits

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: Agree

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: RAS or SPS should generally be regarded as a stop gap measure before transmission expansion or reinforcement becomes available. It should not be used as a substitute for transmission facilities.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: 1. RAS or SPS must be simple and manageable. 2. Nnumber of contingencies triggering a RAS or SPS should be very limited (4 allowed by CAISO). 3. RAS or SPS should generally monitor only local facilities that are either directly connected to the plant or one bus away.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: ISO relies upon tripping of generators to meet single contingency performance requirements. ISO also relies upon planned and controlled load shedding for the proposed Planning Events P4 and P5.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment: Not aware of any

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment:

First, and as a general matter, the TPL-001 standard needs to accurately reflect the roles of PA'S and TP'S in areas with organized competitive markets and where the PA'S and TP'S are not vertically integrated utilities. In those areas, the TPL standard should recognize that compliance with the standard is achieved through the publication of a Plan that identifies system needs – and leaves open to the marketplace the specific mix of resources that investors construct to meet those needs. As a result, the Plan need not be, and should not be, prescriptive as to the resource mix that must be achieved. It is important for plans to be equally open to generation, demand response and transmission and not be presecriptive to the actual resource mix. Further, not all organized competitive markets have a mechanism in place to develop an integrated resource and transmission plan to meet future needs. Some markets conduct forecast assessment, thereby providing signals to market participants to make investment decisions.

Similarly, reflecting the divested nature of the industry in areas operated by ISOs and RTOs, the modeling standards should be reviewed to make sure that asset owners (e.g., generator owners and transmission owners) are required to give information in the level of detail and granularity that will allow PA's and TP's to develop plans and models consistent with these standards.

As highlighted in question 16, DSM should be considered an acceptable solution to system needs. However, DSM is generally considered in meeting resource requirements rather than as one of means to relieve transmission constraints. In planning studies, loads that are identified as DSM type (contracted or potential) are modeled as firm loads for reliability assessment. We would therefore seek the SDT’s suggestion on how specifically DSM should be explicitly modeled or used to aid in achieving transmission reliability in the planning horizon. Further, the drafting team must consider whether DSM providers are covered in the Compliance Registry and how the NERC Standards should obligate them to provide the requisite information to PA'ss and TP's so that they are fully taken into account.

Finally, the standards need to be improved to better distinguish the responsibility of Planning Authorities versus Transmission Planners. Currently, the Standard refers to both entities as carrying out the requirements. This appears to be reundant.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

<table>
<tr><th colspan="3">Individual Commenter Information
(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td colspan="3">Name: Paul Rocha</td></tr>
<tr><td colspan="3">Organization: CenterPoint Energy</td></tr>
<tr><td colspan="3">Telephone: 713-207-2768</td></tr>
<tr><td colspan="3">E-mail: paul.rocha@centerpointenergy.com</td></tr>
<tr><td>NERC Region (check all Regions in which your company operates)</td><td></td><td>Registered Ballot Body Segment (check all industry segments in which your company is registered)</td></tr>
<tr><td rowspan="10">☒ ERCOT
☐ FRCC
☐ MRO
☐ NPCC
☐ RFC
☐ SERC
☐ SPP
☐ WECC
☐ NA – Not Applicable</td><td>☒</td><td>1 — Transmission Owners</td></tr>
<tr><td>☐</td><td>2 — RTOs and ISOs</td></tr>
<tr><td>☐</td><td>3 — Load-serving Entities</td></tr>
<tr><td>☐</td><td>4 — Transmission-dependent Utilities</td></tr>
<tr><td>☐</td><td>5 — Electric Generators</td></tr>
<tr><td>☐</td><td>6 — Electricity Brokers, Aggregators, and Marketers</td></tr>
<tr><td>☐</td><td>7 — Large Electricity End Users</td></tr>
<tr><td>☐</td><td>8 — Small Electricity End Users</td></tr>
<tr><td>☐</td><td>9 — Federal, State, Provincial Regulatory or other Government Entities</td></tr>
<tr><td>☐</td><td>10 — Regional Reliability Organizations and Regional Entities</td></tr>
</table>

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: Firm transaction obligations are not used throughout all regions in NERC. Change "including firm transaction obligations" to "including firm transaction obligations where applicable."**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	

Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☐Do not agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.

- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: The number and type of sensitivity studies should be left to the judgement of Transmission Planners. Having too many prescriptive requirements results in concentrating on meeting the requirements rather than on formulating the most effective and efficient improvements.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: See comment to Q12.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒
Comment: The number and type of sensitivity studies should be left to the judgement of Transmission Planners.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒
Comment: CenterPoint Energy is not aware of DSM ever being identified as an effective option to correct a transmission system deficiency. If such an application of DSM was identified and implemented, load growth would quickly negate the DSM impact, and other measures would have to be taken.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☒
Comment: Many problems identified in future studies and associated transmission improvements are fictitious due to the speculative nature of predicting load and generation growth. Requiring exhaustive studies to determine the full impact of fictitious transmission projects is unnecessarily prescriptive and burdensome, and provides little, if any, value in identifying and solving real transmission problems.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: This is overly prescriptive. Allow each Transmission Plannner to determine the best way to handle planned projects.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to “raise the bar.” Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	The forced outage of two independent lines has a low probability of occurrence and should be considered an improbable event with non-consequential load loss permitted.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒

Comment: The loss of a non-bus tie breaker due to an internal fault has a low probability of occurence and should be considered an improbable event with non-consequential load loss permitted. However, the loss of any breaker, whether by internal fault, external flashover, or stuck breaker, should not result in a cascading failure.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: The loss of either a generator, a Transmission cirucit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV) has a low probability of occurrence and should be considered an extreme event with non-consequential load loss permitted.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	CenterPoint Energy believes the assumption that this is a high probability event is incorrect. Furthermore, an absolute requirement prohibiting non-consequential loss of load has economic and landowner impacts that cannot be ignored.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	CenterPoint Energy believes the assumption that this is a high probability event is incorrect. Furthermore, an absolute requirement prohibiting non-consequential loss of load has economic and landowner impacts that cannot be ignored.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	CenterPoint Energy believes the assumption that this is a high probability event is incorrect. Furthermore, an absolute requirement prohibiting non-consequential loss of load has economic and landowner impacts that cannot be ignored.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	CenterPoint Energy believes the assumption that this is a high probability event is incorrect. Furthermore, an absolute requirement

[1] System adjustment can be manual or automatic

		prohibiting non-consequential loss of load has economic and landowner impacts that cannot be ignored.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment: Separating the stability requirements into a second table improved the clarity.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: CenterPoint Energy does not see the distinction between system stability and plant stability studies as defined in the draft standard. Meeting the performance requirements set in R4.5 should suffice for all stability studies. The requirements in R4.6 seem overly prescriptive and could potentially result in numerous studies being required that would have very little positive effect on transmission systems throughout the country.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: CenterPoint Energy agrees with the SDT's assessment.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: CenterPoint Energy includes the dynamic effects of induction motor loads in stability studies. However, this requirement is overly prescriptive since some utilities may not need to include the dynamic effects of induction motors and should not be required to do so.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☒ No ☐
Comment: FPA section 215(i)(2) "does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services." However, adherence to TPL-001-1 as currently drafted, will require, de facto, the construction of additional transmission facilities. CenterPoint Energy believes this standard goes far beyond the legislative intent of mandatory reliability standards and will result in construction of transmission capacity in order to remain compliant.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:

TPL-001-1 focuses solely on reliability to the exclusion of economic cost/benefits, prudent avoidance, and landowner impacts, which have been the hallmarks of good utility practice that have governed transmission planning and construction for decades. FPA section 215(i)(2) "does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services." However, adherence to TPL-001-1 as currently drafted, will require, de facto, the construction of additional transmission facilities. CenterPoint Energy believes this standard excludes proven, historical good utility practice to reach far beyond what is intended by the FPA.

TPL-001-1 contains an excessive number of requirements (over 50). The SDT should consider the removal or modification of the following unnecessary, redundant or overly prescriptive requirements:

R1.1. This is a modeling requirement and should be incorporated into the modeling (MOD) standards. Remove or modify this requirement to eliminate any redundancy with existing modeling standards. If certain subrequirements of R1.1 of TPL-001 are not currently requirements in a MOD standard, it should be questioned, then, whether or not these specific subrequirements are actually needed in ANY standard.

R2.1.3 and R2.4.3 should be removed because they introduce new, vague requirements.

R2.2. Analysis beyond five years has little value due to the speculative nature of predicting load and generation growth. Furthermore, ERCOT does not annually create Long-Term Planning Horizon cases because ERCOT does not believe it is necessary. This requirement should be removed.

R2.5 and R4.6. These requirements are overly prescriptive and unnecessary for the reasons stated in the response to Q32. They should be removed.

R2.7.1 through 2.7.5. Requiring Corrective Action Plans that address how performance requirements will be met is reasonable; however, these standard requirements are overly prescriptive and unnecessary. R2.7.1 through R2.7.5 would result in the development, documentation and explanation of fictitious solutions to fictitious problems. They should be removed.

R3.3.2.1. The requirement to identify consequential load loss for single contingencies in the Planning Assessment is unnecessary and burdensome and should be removed.

R5. The roles of the Transmission Planner and Planning Coordinator are already addressed in the approved NERC definitions and further described in the approved NERC Reliability Functional Model. This requirement is unnecessary and should be removed.

Table 1 and Table 2 - P4, P5, P8, and P9. Including all combinations of two components (generator, Transmission circuit, transformer, monopolar DC line) with generation adjustments is impractical and overly burdensome. For multiple contingencies, CenterPoint Energy recommends including only two-circuit tower lines and the two components (generator, Transmission circuit, transformer, monopolar DC line) that would be cleared by a breaker failure (i.e., stuck breaker).

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1 Version 1 of SAR posted for comment from April 2, 2002 through May 3, 2002.
2 Version 2 of SAR posted for comment from May 5, 2004 through June 5, 2004.
3 Version 3 of SAR posted on November 18, 2005.
4 SAR approved on April 30, 2006.
5 Version 1 of Supplemental SAR posted for comment from February 15, 2007 through March 16, 2007.
6 Version 2 of Supplemental SAR posted on April 9, 2007.
7 Version 1 of revised standard(s) posted for comment on September 17, 2007.

Proposed Action Plan and Description of Current Draft:

The SDT has established an aggressive schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 2Q08. The current draft is the first iteration of the revision of existing standards TPL-001 through TPL-006 and includes one revised standard, TPL-001-1, replacing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. TPL-005 & -006 will be addressed later in the project. Violation Risk Factors, Time Horizons, Measures, Compliance and Implementation Plans will be included in subsequent postings.

Future Development Plan:

Anticipated Actions	**Anticipated Date**
1. Respond to comments from first posting of standard(s) and submit revision 1 of the standard(s).	4Q2007
2. Respond to comments from second posting of standard(s) and submit revision 2 of the standard(s).	4Q2007
3. Submit revision 3 of the standard(s) for balloting.	4Q2007
4. Submit standard(s) for recirculation balloting.	2Q2008
5. Submit standard(s) to BOT.	2Q2008
6.	
7.	

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Base Case: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch, including firm transaction obligations where applicable, assumed to supply the connected Load. The models also reflect Facility Ratings.

Consequential Load Loss: Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.

Extreme Events: Events which are more severe than Planning Events and have a low probability of occurrence.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond.

Near-Term Transmission Planning Horizon: Transmission planning period that covers Years One through five.

Non-Consequential Load Loss: Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.

Planning Assessment: Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.

Planning Events: Events which require Transmission system performance requirements to be met.

Plant Stability Study: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.

System Stability Study: Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.

Year One: The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies.

A. Introduction

1. Title: Transmission System Planning Performance Requirements

2. Number: TPL-001-1

3. Purpose: Establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. Applicability:

4.1. Functional Entity

4.1.1. Planning Coordinator.

4.1.2. Transmission Planner.

4.1.3. Resource Planner.

4.1.4. Load-Serving Entity.

4.1.5. Transmission Owner.

4.1.6. Generator Owner.

5. Effective Date: TBD

B. Requirements

R1. Each Resource Planner, Transmission Planner, Transmission Owner, Generator Owner, and Load-Serving Entity shall each provide its respective Planning Coordinator with the following modeling information required for System performance studies upon request (within 30 calendar days) : *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

~~**R1.1.** Load forecasts adhering, at a minimum, to the following criteria:~~

~~**R1.1.1.** Use of expected Load mix based on the actual or expected aggregate mix of industrial, commercial, and residential Loads.~~

~~**R1.1.2.** Based on normal weather patterns as agreed to by the Planning Coordinator(s) and the Transmission Planner(s) for the area(s) of their responsibility.~~

~~**R1.1.3.** Identification of Demand Side Management (DSM) Load reductions consistent with operational requirements.~~

R1.2. Load models with supporting rationale that include power factor data based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements.

R1.3. Firm transfers/Interchange Schedules and resources required to supply Load for each Balancing Authority.

R1.4. Known planned outages and long-term outages for Transmission and generation equipment including protective relays with consideration given to spare equipment strategy.

R1.5. Planned Facilities defined in accordance with the documented criteria of the Planning Coordinator, including but not limited to: Transmission Lines, generators, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies.

R2. Each Transmission Planner and Planning Coordinator shall conduct and document the results of its annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, and shall cover steady state analyses, short circuit analyses, and Stability analyses including both System and plant Stability. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R2.1. The steady state portion of the Near-Term Transmission Planning Horizon Planning Assessment shall address all five years of the assessment period and be supported at a minimum by the following annual current studies,, supplemented with qualified past studies as shown in Requirement R2.6:

R2.1.1. System peak Load for either Year One or year two, and year five.

R2.1.2. System Off-Peak Load for one of the five years.

~~**R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation with the rationale for the selected sensitivity(ies) shall be supplied:~~

~~**R.2.1.3.1.** Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.~~

~~**R.2.1.3.2.** Modification of expected transfers.~~

~~**R.2.1.3.3.** Unavailability of long lead time facilities.~~

~~**R.2.1.3.4.** Variability and outages of reactive resources.~~

~~**R.2.1.3.5.** Generation additions, retirements, or other dispatch scenarios.~~

~~**R.2.1.3.6.** Decreased effectiveness of controllable Loads and Demand Side Management.~~

~~**R.2.1.3.7.** Modification of planned Transmission outages.~~

~~**R2.2.** For the steady state portion of the Long-Term Transmission Planning Horizon Planning Assessment, at a minimum, a current System peak Load study is required annually for one of the years in the assessment period to support the annual Planning Assessment.~~

~~**R2.2.1.** To accommodate any known longer lead time projects that may take longer than ten years to complete, the Planning Assessment shall be extended accordingly.~~

R2.3. The short circuit portion of the Planning Assessment shall be conducted annually and supported by current or past studies.

R2.3.1. A current study shall be performed if changes in the BES result in increased fault currents such as resource additions and other Facility changes that result in reductions in impedance.

R2.4. The System Stability portion of the Near-Term Transmission Planning Horizon Planning Assessment shall address all five years of the assessment period, and be supported by current or past studies. The following studies are required:

R2.4.1. System peak Load for one of the five years. For peak System Load levels, the Load model shall include the dynamic effects of induction motor Loads.

R2.4.2. System Off-Peak Load for one of the five years.

~~**R2.4.3.** Sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run with documentation provided explaining the rationale for the selected sensitivity(ies):~~

~~**R.2.4.3.1.** Variations in Load model assumptions.~~
~~**R.2.4.3.2.** Expected simultaneous transfers including non-firm transfers.~~
~~**R.2.4.3.3.** Unavailability of long lead time facilities.~~
~~**R.2.4.3.4.** Reactive dispatch of generators and other reactive power devices.~~
~~**R.2.4.3.5.** Generation additions, retirements, or other dispatch scenarios.~~

~~**R2.5.** The plant Stability portion of the Planning Assessment shall be analyzed consistent with Requirement R4.6 with studies for the year when the following occur:~~

~~**R2.5.1.** New generator(s) are added or generation modifications are made such as increasing generation capability, replacing the exciter or addition of a power System stabilizer.~~

~~**R2.5.2.** Material changes in the electrical vicinity of existing generation are made such as the addition or removal of a Transmission Line at or near the point of Interconnection.~~

R2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

R2.6.1. For steady state analysis: if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes.

R2.6.2. For short circuit analysis: if the study is less than five years old and no material changes have occurred to the System in the intervening period.

R2.6.3. For plant and System Stability analysis: until material changes in the System make the study no longer valid. Material changes in the system include the addition of a Transmission Line or a generator.

R2.7. For Planning Events shown in Table 1 – Steady State Performance and Table 2 – Stability Performance, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed over time but shall meet the performance requirements in the tables. Such plans shall:

~~**R2.7.1.** Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~

~~**R.2.7.1.1.** For the Near-Term Transmission Planning Horizon, include both a project initiation date as well as an in-service date.~~

~~**R.2.7.1.2.** For the Long-Term Transmission Planning Horizon, provide an in-service year..~~

~~**R2.7.2.** Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables.~~

~~**R2.7.3.** Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~

~~**R2.7.4.** Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~

~~**R2.7.5.** Be reviewed in subsequent annual Planning Assessments as to implementation status of identified System Facilities and Operating Procedures.~~

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to contingencies in Table 1 – Steady State Performance. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R3.1. Studies shall determine whether the BES meets the performance requirements in Table 1 – Steady State Performance.

R3.2. Contingency analyses shall simulate the removal of all elements including those that System protection is expected to disconnect for each Contingency without operator intervention.

R3.2.1. For all generators, studies shall consider the minimum steady state voltage limitations of all generators and identify how the generators are treated in the steady state simulation.

R3.2.2. For all Transmission lines, studies shall consider relay loadability and identify how loadability is treated in the steady state simulation.

R3.3. For Steady State studies:

R3.3.1. Performance criteria for System normal conditions and for Planning Events in Table 1 – Steady State Performance shall be met.

R3.3.2. Evaluations shall be performed for single Contingencies (identified in Table 1 – Steady State Performance).

~~**R.3.3.2.1.** Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment.~~

R.3.3.2.2. Following single Contingency events, System adjustments other than shedding of firm Load or curtailment of firm transfers are permitted to meet performance requirements provided these adjustments can be accomplished within the time period allowed by the applicable time limited ratings.

R3.3.3. Those Planning Event Contingencies in Table 1 – Steady State Performance not covered in Requirement R3.3.2 that are expected to produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results.

R3.4. Those Extreme Events in Table 1 – Steady State Performance that are expected to produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. If the Extreme Events analysis concludes there are Cascading Outages caused by the occurrence of Extreme Events, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted.

R3.5. Manual and automatic generation run-back is allowed as a response to single and multiple Contingencies as long as Facility Ratings are not exceeded.

R3.6. Manual and automatic generation tripping is allowed for multiple Contingencies and for single Contingencies only in situations that meet all of the following conditions:

R3.6.1. TBD

Note: WECC has informed the SDT that it will be submitting an Interconnection-wide regional variance to allow for manual and automatic generation tripping for single Contingencies. The regional variance will be justified based on physical System differences in the western Interconnection. WECC is developing a white paper to support this position. The actual text of the regional variance will be included in the next posting of this standard.

R4.

For the Stability portion of the Planning Assessment, as described in Requirement R2.4

and Requirement R2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 2 – Stability Performance. The studies shall cover both System Stability and plant Stability. The following requirements apply to both System Stability and plant Stability studies unless otherwise noted. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R4.1. Studies to meet the performance requirements in Table 2 – Stability Performance shall use computer Stability simulations that analyze the response of the BES.

R4.2. Contingency analyses shall simulate the removal of all elements including those that System protection is expected to disconnect for each Contingency without operator intervention.

R4.3. Studies shall consider the voltage ride through capability of all generators and identify how the generators are treated in the simulation.

R4.4. Studies shall identify any planned upgrades (including protection and control modifications) needed to meet the performance requirements of the Planning Events of Table 2 – Stability Performance and validate their effectiveness.

R4.5. For the System Stability study:

R4.5.1. At a minimum, those Planning Event Contingencies in Table 2 – Stability Performance that would produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information with an explanation of why the remaining Contingencies would produce less severe System results.

R4.5.2. At a minimum, those Extreme Events in Table 2 – Stability Performance that would produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. If the Extreme Events analysis concludes there are Cascading Outages, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted.

~~**R4.6.** For the Plant Stability studies:~~

~~**R4.6.1.** Shall be performed for individual generating units 20 MW or greater directly connected through a step-up transformer to the BES and for generating units at the same location which total 75 MW or greater, directly connected through their step-up transformer(s) to the BES.~~

~~**R4.6.2.** Shall be performed for changes in the real power output of a generating unit by more than 10% of the existing capability or more than 20 MW whichever is greater.~~

~~**R4.6.3.** Shall be performed and evaluated for those Planning Events that would produce more severe System impacts and the rationale for the Contingencies selected for evaluation shall be available as supporting~~

~~information and shall include an explanation of why the remaining Contingencies would produce less severe System results. The identified Contingencies, at a minimum, shall be evaluated.~~

~~**R4.6.4.** Shall meet Performance requirements for Planning Events in Table 2 – Stability Performance.~~

~~**R5.** Each Transmission Planner and Planning Coordinator shall determine and identify individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*~~

R6. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among affected entities, coordinating analysis of these results through an open and transparent peer review process. *[Violation Risk Factor: TBD] [Time Horizon: TBD]* This distribution shall include:

R6.1. Transmission Planners within the Planning Coordinator's area

R6.2. Transmission Planners of neighboring impacted areas

R6.3. Planning Coordinators of neighboring areas

Table 1 – Steady State Performance

Performance Requirements For all Planning Events: • Equipment Ratings shall not be exceeded. • System steady state voltages and post-transient voltage deviation shall be within acceptable limits established by the Planning Coordinator (or Transmission Planner if more restrictive.) • Voltage instability, cascading outages, and uncontrolled islanding shall not occur. • Consequential Load loss is allowed for all cases shown. • Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency. • Simulate Normal Clearing unless otherwise specified.

Planning Events

#	Event	Interruption of Firm Transfer Allowed (does not result in loss of Load)	Non-Consequential Load Loss Allowed
P1 (single Contingency)	Loss of: 1. A generator 2. A Transmission circuit 3. A transformer 4. A shunt device (including FACTS devices)	No	No
P2 (single Contingency)	Loss of: 1. Bus section above 300 kV 2. Non-bus tie breaker (above 300 kV) due to internal fault 3. Single pole of a DC line	Yes, if transfer is dependent on the outaged DC line No otherwise	No
P3 (multiple Contingency)	Loss of either a generator, Transmission circuit, a transformer with low side voltage rating above 300 kV, or a bus and a stuck non-bus tie breaker (above 300 kV)	Yes, if transfer is dependent on the outaged DC line No otherwise	No
P4 (multiple Contingency)	1. Loss of a generator followed by a System adjustment followed by the loss of a generator. 2. Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line 3. Loss of a generator followed by a System adjustment followed by the loss of a Transmission circuit 4. Loss of a generator followed by a System adjustment followed by the	Yes, if transfer is dependent on the outaged DC line No otherwise	No

	loss of a transformer		
P5 (multiple Contingency)	Above 300 kV, the loss of: 1. A Transmission circuit followed by a System adjustment followed by the loss of another Transmission circuit 2. A Transmission circuit followed by a System adjustment followed by the loss of a transformer with low side voltage rating above 300 kV 3. A transformer with low side voltage rating above 300 kV followed by a System adjustment followed by the loss of another transformer	Yes	No
P6 (single Contingency)	Loss of: 1. A bus tie breaker due to internal fault 2. A bipolar DC line or an asynchronous tie line 3. A non-bus tie breaker (below 300 kV) due to internal fault 4. A bus section below 300 kV	Yes	Yes
P7 (multiple Contingency)	Loss of: 1. A bus section above 300 kV and a stuck bus tie breaker 2. Either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (below 300 kV)	Yes	Yes
P8 (multiple Contingency)	Below 300 kV, the loss of: 1. A Transmission circuit followed by a System adjustment followed by the loss of another Transmission circuit 2. A Transmission circuit followed by a System adjustment followed by the loss of a transformer 3. A transformer followed by a System adjustment followed by the loss of another transformer	Yes	Yes
P9 (multiple Contingency)	1. Loss of any two circuits on a common structure (excluding where multiple circuits share a common structure for no more than one mile) 2. Loss of a generator followed by a System adjustment followed by the loss of a monopolar or bipolar DC line, or an asynchronous tie line 3. Loss of a DC line (monopolar or bipolar) or asynchronous tie followed by a System adjustment followed by the loss of a second DC line (monopolar or bipolar) or asynchronous tie 4. Loss of a DC line (monopolar or bipolar) or asynchronous tie followed by a System adjustment followed by the loss of a Transmission circuit	Yes	Yes

	5. Loss of a transformer followed by a System adjustment followed by the loss of a DC line (monopolar or bipolar) or asynchronous tie line 6. Loss of a transformer followed by a System adjustment with a spare transformer available followed by the loss of another transformer		
Extreme Events			
Evaluation Requirements For all Extreme Events: 1. See Requirement R3.4 2. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency. 3. Simulate Normal Clearing unless otherwise specified.			
Extreme Event Descriptions			
1. Loss of a single generator, Transmission circuit, DC line, or transformer forced out of service followed by another single generator, Transmission circuit, DC line, or transformer forced out of service prior to System adjustments. **2.** Local area events affecting the Transmission System such as: a. Loss of tower line with three or more circuits b. Loss of all Transmission lines on a common right-of-way c. Loss of switching station or substation (loss of one voltage level plus transformers) d. Loss of all generating units at a station e. Loss of a large Load or major Load center **3.** Wide area events affecting the Transmission System such as: a. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation b. A successful cyber attack c. Regulation that restricts or eliminates the use of a river or lake or other body of water as the cooling source for generation d. Shutdown of a nuclear power plant(s) and other facilities a day or more prior to a hurricane, tornado or wildfire, or for other common causes e. Regulation that restricts or eliminates the use of a river or lake or other body of water as the cooling source for generation f. Shutdown of a nuclear power plant(s) and other facilities a day or more prior to a hurricane, tornado or wildfire, or for other common causes such as problems with similarly designed plants g. The loss of older Transmission lines which may not be constructed to meet an entity’s present radial ice or wind loading requirements, while the newer or stronger Transmission lines remain in service h. Other events based upon operating experience			

Table 2 – Stability Performance Table

Performance Requirements For all Planning Events: • The System shall be stable[1] • Dynamic voltages shall be within acceptable limits established by the Planning Coordinator or Transmission Planner (if more restrictive) • Uncontrolled islanding and Cascading Outages shall not occur • Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency. • Simulate Normal Clearing unless otherwise specified.			
Planning Events			
#	**Initial Condition**	**Event**	**Non-Consequential Load Loss Allowed**
P1 (single Contingency)	System normal	Single Line Ground (SLG) fault on, a 3 Phase (3Ø) fault on, or an unexpected loss without a fault of (whichever is worst): 1. A generator 2. A Transmission circuit 3. A transformer	No
P2 (single Contingency)	System normal	1. SLG fault on bus section above 300 kV 2. SLG internal fault in non-bus tie breaker (above 300 kV) 3. A single pole block of a DC line	No
P3 (multiple Contingency)	System normal	SLG fault on either a generator, Transmission circuit, a transformer, or a bus and a stuck[2] non-bus tie breaker (above 300 kV)	No
P4 (multiple Contingency)	A single generator out of service followed by System adjustments	1. Apply a P1.1 Contingency. 2. Apply a P2.3 Contingency. 3. Apply a P1.2 Contingency. 4. Apply a P1.3 Contingency.	No
P5 (multiple Contingency)	A Transmission circuit above 300 kV out of service followed by System adjustments	1. Apply a P1.2 Contingency. 2. Apply a P1.3 Contingency.	No

	A transformer with low side voltage rating above 300 kV out of service followed by System adjustments	3. Apply a P1.3 Contingency.	
P6 (single Contingency)	System normal	1. SLG internal fault in bus tie breaker 2. A bipolar block of a DC line 3. SLG internal fault in non-bus tie breaker (below 300 kV) 4. SLG fault on bus section (below 300 kV)	Yes
P7 (multiple Contingency)	System normal	1. SLG fault on a bus section above 300 kV and a stuck bus tie breaker 2. SLG fault on either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (below 300 kV)	Yes
P8 (multiple Contingency)	A Transmission circuit below 300 kV out of service followed by System adjustments A transformer with low side voltage rating below 300 kV out of service followed by System adjustments	1. Apply a P1.2 Contingency. 2. Apply a P1.3 Contingency. 3. Apply a P1.3 Contingency.	Yes
P9 (multiple Contingency)	System normal A single generator out of service followed by System adjustments A DC circuit out of service followed by	1. SLG fault on each circuit of any two circuits on a common structure (excluding events where multiple circuits share a common structure for no more than one mile). 2. Apply a P6.2 Contingency. 3. Apply a P2.3 Contingency. 4. Apply a P1.2 Contingency.	Yes

	System adjustments A transformer out of service followed by System adjustments A spare transformer inserted to replace an outaged transformer followed by System adjustments	5. Apply a P2.3 Contingency. 6. Apply a P1.3 Contingency.	
Extreme Events			
Evaluation Requirements For all Extreme Events: • See Requirement R4.5.2 in the text • Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency. • Simulate Normal Clearing unless otherwise specified.			
1. 3Ø fault on generator with stuck breaker 2. 3Ø fault on Transmission circuit with stuck breaker 3. 3Ø fault on transformer with stuck breaker 4. 3Ø fault on bus section with stuck breaker 5. 3Ø internal fault in breaker 6. 3Ø fault on two or more circuits on a common structure 7. SLG or 3Ø fault on all Transmission lines on a common right-of-way 8. 3Ø fault on switching station or substation (loss of one voltage level plus transformers) 9. 3Ø fault with loss of all generating units at a station			

Notes:

1. System stable means:

a. Angular stability:

i. For Planning Events P1 and P3.2: No generating unit or units shall be allowed to pull out of synchronism. A generator being disconnected from the system by fault clearing action or by a Special Protection Scheme is not considered pulling out of synchronism.

ii. For all other Planning Events: No generating unit or units totaling more than the contingency reserve (spinning reserve) of the Balancing Authority shall be allowed to pull out of synchronism. Generators that pull out of synchronism must have out-of-step protection and the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of any transmission system elements other than the generating unit and its direct connection facilities.

iii. For all Planning Events: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator or Transmission Planner (if more restrictive).

b. General: Unplanned islanding of portions of the system shall not occur for Planning Events.

2. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) breaker, only one pole is assumed to remain closed.

C. Measures

M1. To be supplied at a later date.

E. Regional Variances

1. WECC Interconnection-wide waiver is under development (see Requirement R3.6.2).

Version History

Version	Date	Action	Change Tracking
1		Revision of TPL-001-0 as per Project 2006-02; includes merging requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-1	Not employed due to scope of revision

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	David M Conroy	
Organization:	Central Maine Power Company	
Telephone:	(207) 626-9750	
E-mail:	david.conroy@cmpco.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: There are a few undefined terms in this definition: "Transmission System" and "interconnected Transmission System". The definition needs to specifically identify what should be modeled and in a manner consistent with other NERC definitions. The definition refers to Facility ratings rather than the general reference to FAC-008 & FAC-009**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Modify to "Events which are more severe,but have a lower probability of occurrence, than Planning Events".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☒Do not agree.
Q4. **Comment: "A Planning Assessment period that covers years six through ten", is sufficient for the standard." Suggest changing the name to Long-Term Planning Assessment.**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: Suggest changing the name to Near-Term Planning Assessment, and introduce the description the same was as above.**	
Q6. **Non-Consequential Load Loss:** Load loss other than	☒Agree.

Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Eliminate "capital" from the definition. It is not defined or consistently applicable to the standard. Reference to vague "other factors, such as asset conditions and age" should be removed from this standard; there are no consistent definitions or industry standards on which to base this requirement, nor does it appear to be a necessary addition to the standard.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Propose, "Events for which Transmission performance requirements must be met".**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: See comment on Q9; proposed modification, "Study of the System or portions of the System to determine whether plant and system angular Stability is maintained, power oscillations are damped, and voltages during the dynamic simulation stay within acceptable perfomance limits.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: Modify to, "The first year that a Tranmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner completes its annual studies."**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement to mitigate consequences of problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System shall be considered, and documentation with the rationale for the sensitivity testing shall be supplied. The sensitivity case(s) may include one or more of the following conditions:"

2.1.3.3 should refer only to planned facilities that may be delayed. 2.1.3.4 - "variability" is too vague for a standard; the standard needs to be more specific as to the intent. 2.1.3.7 should be consistent with 1.4. These comments also apply to 2.4.3.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement to mitigate consequences of problems highlighted as a result of one of the sensitivities.

Reasonably stressed conditions are dependent upon the study area under review and the standard is not likely to be able to be crafted to provide sufficent and consistent direction. However, it might be helpful if the standard clarified whether the base case should include any unplanned generator outages or whether, aside from potential sensitivities, unplanned generator outages are considered only through P1, P3 or P4 Contingencies. If the standard addresses unplanned generator outages only through P1, P3 and P4, then it is recommended that a mandatory sensitivity analysis, with required mitigation, include various potential combinations of a reasonable amount of unplanned outages. The combinations should be based on the part of the system that is under study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐

Comment: The standard is unclear whether or not it mandates the requirement to mitigate consequences of problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System should be considered. Sensitivity case(s) might include among the following conditions:" 2.4.3 shold mimic 2.1.3 except in regard to load models.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: There is no need for sensitivity analysis.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: DSM should be included to the extent that its performance is sufficiently and consistently understood. The standard does not use the term "optimal" Therefore, the Drafting Team appears to be interpreting the Standard to require a vertically-integrated Planner to produce a so-called optimal-mix of resources plan. This would be an incorrect assumption and is not required. In areas with independent planners and competitive wholesale markets, it is sufficent to identify system needs and produce a plan that identifies regulated transmission solutions in the event that market-based resources (such as DSM) do not address those identified needs. Therefore, while DSM can be as effective a resource as generation, per Commission Orders,

in areas with ISOs/RTOs and a competitive wholesale market, the NERC Standard cannot prescribe the development so-called optimized (as is suggesgted by the Drafting Team) resource-mix plans, as identified by a central planner.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐

Comment: The study area should be based upon planning expertise and knowledge of the system, giving due consideration to external impacts.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐

Comment: They should be viewed differently in the Near-Term. However, these should be defined terms.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐

Comment: It is unclear as to what the commited project is being removed from. Suggested language "…removed from the plan…".

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Given the low probability of extended overlapping outages of overhead facilities, systems have been designed assuming that load shedding following the loss of a second transmission line is permissible. Eliminating any allowance for load shedding for this condition may require significant system expansion and cost to to customers. However, it would be reasonable to consider establishing an upper bound to the amount of load that could be shed for these purposes.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Should also consider the initial loss of a transformer, followed by the loss of a Transmission circuit. This should state a transformer with a "high-side" rating above 300 kV.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	This should state a transformer with a "high-side" rating above 300 kV.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of 2 additional generators.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a monopolar DC line
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a Transmission circuit
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a transformer

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm

[1] System adjustment can be manual or automatic

transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: This should also apply to firm transfers via single or double ac facilities as well. In either case, the transfer could be linked to dedicated facilities.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Difficult to envision how such an event would occur.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: This requirement is too specific and limited. Induction motors are only one component of a complex load model. Complex load models are not always necessary, nor are they always the most conservative, depending on the analysis that is being conducted. Where complex load models are required, they should be considered; this may involve use of complex motor and lighting loads or polynomial load representations

with or without frequency dependence. This question also suggests the need for an industry standard regarding transient voltage recovery.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Manual or automatic adjustments should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment. Manual system adjustment should be allowed in between the multiple Contingencies described in P5, provided that the adjustment can be made between contingencies using short-term reserves (10-30 minute).

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: Generation runback should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐

Comment: However, this should only be allowed where failure of an automatic runback that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: Only allowed where the failure of an SPS that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Only allowed where SPS failure would not have significant adverse impact on the Bulk Electric System; non-Consequential loss of load should be allowed up to an amount potentially specified in the standard.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: System must remain stable with acceptable voltages and all equipment within applicable emergency limits.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☒
Comment: Unsure due to ambiguities in the standard. Depending upon the final standard, New England may need exceptions for existing facilities or allowance for a transition period to develop a compliance plan.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: There should be a "P0" standard that applies to system performance without any contingencies.

Standard should be clear that stabiltiy analysis is not required for Long-Term Planning Assessment.

R.1.1 Load forecasts should be addressed in MOD standards, not TPL.

R 1.4 This should only refer to known long-term outages, not planned outages. Delete "including protective relays"; this is addressed through other provisions.

R.2.1 Shorten "Near-Term Transmission Planning Horizon Planning Assessment" to "Near-Term Planning Assessment".

R 2.2 Shorten "Long-Term Transmission Planning Horizon Planning Assessment" to "Long-Term Planning Assessment".

R2.1, 2.2, 2.3 & 2.4 – The initial paragraph should have identical language regarding 'annual', and 'current or past' aspects.

R2.1.1 There should not be a requirement to look at years one and two; a 5 year study should be sufficient. If there has been an ongoing 5 year study, there should be no major unexpected problems occurring in years 1 and 2. Studies of earlier years should only be required if an unanticipated event occurred that had not been considered in prior studies. The TPL should not address shorter term "Operating Studies" or operating issues.

R 2.2.1 Modify to "If any known projects have a lead time that is longer than ten years, the Planning Assessment shall be extended accordingly."

R 2.6 Steady-state, short circuit, and stability analysis should be required no more than every 5 years unless there is a significant change the system.

R 2.6.1 Remove reference to "market structure changes". The purpose of it's inclusion is unclear.

R 2.7.1.1 Project initiation date should be deleted. If it is retainted, it needs to be defined.

R 2.7.3 Committed and Proposed projects should be defined.

R 3.2.1/R 4.3 - What is the intent of this requirement? There should probably be an MOD associated with Generator Owner requirement to provide related generator protection/ limiter data or other plant information.

R 3.4/R 4.5.2 Remove the requirement to implement changes to reduce or mitigate the likelihood of such consequences of Extreme Events. This may not be reasonable or achieveable.

R 3.2 Sectionalizing schemes shall be considered when reflecting the post-contingent system.

R 3.2.2 - Propose deleting this. Line ratings should already take relay loadability into account.

R 3.3.2.1 - Proposed deleting "expected duration". This would be dependent upon the damage to the element due to the iniating event and other factors.

R 3.3.2.2 - The requirements of this section do not match P6.

R 3.3.3 - Change introductory language to read "Those multiple Contingencies that are…"

R 3.5 - Generation tripping should be allowed as well as generation run-back. In addition, all performance requirements shall be met, rather than just meeting facility rating requirements. Suggested lanague "Manual and automatic generation run-back and/or generation tripping is allowed as a response to single and multiple Contingencies as long as the performance requirements of this standard are met." If these changes are accepted, R 3.6 can be deleted.

R 4 and R 4.1 - The language should be made similar to R 3 and R 3.1.

Suggest bringing language similar R4.4 into the R 3, the steady state section.

R 4.2 - High speed automatic reclosing schemes shall be considered.

R 6.3 - Change to read "Planning Coordinators of neighboring impacted areas".

Table 1 3 b and c Extreme Event descriptions are vague concepts that cannot be practically simulated. 3 d and e are not reasonable or practically useful to simulate.

Table 1, P8 - Language needs to be clarifed as to how the 300 kV threshold is to be treated for transformers. Is this for the high side, low side, or both sides? P5 is much clearer.

Table 2 - Clarification needs to be made that the faults being simulated are permanent faults. This can be addressed under the "Performance Requirements" portion at the beginning of the table, or modify each fault description.

Table 2 P9. Recommend that this be changed to require that faults should be on different phases of each of two adjacent transmission circuits on a multiple circuit transmission tower

Table 1, P9(6) and Table 2 P9 - It is unclear as to what is meant by "A spare transformer inserted to replace an outaged transformer followed by System adjustments". Unclear as to what is to be tested.

General comment - Transmission System is used throughout the document and is an undefined term

The New England Transmission Owners and ISO New England transmission planners met several times to discuss the proposed standard and develop consensus comments based on our experience. The preceding comments are what was developed.

Attached to the e-mail sending these comments is the September 12 Draft 1 TPL-001-1 Reliability Standard in Word format, red-lined with changes to the posted standard which are intended to reflect all of the comments above. This document was maintained by Central Maine Power Company during the course of the New England transmission planner discussions, and any variance (though none are expected) in not intended.
It is expected that this red-lined TPL document will be helpful to the ATFN SDT in reviewing our comments.

Standard Development Roadmap, red-lined with New England Transmission Planners' comments

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Version 1 of SAR posted for comment from April 2, 2002 through May 3, 2002.
2. Version 2 of SAR posted for comment from May 5, 2004 through June 5, 2004.
3. Version 3 of SAR posted on November 18, 2005.
4. SAR approved on April 30, 2006.
5. Version 1 of Supplemental SAR posted for comment from February 15, 2007 through March 16, 2007.
6. Version 2 of Supplemental SAR posted on April 9, 2007.
7. Version 1 of revised standard(s) posted for comment on September 17, 2007.

Proposed Action Plan and Description of Current Draft:

The SDT has established an aggressive schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 2Q08. The current draft is the first iteration of the revision of existing standards TPL-001 through TPL-006 and includes one revised standard, TPL-001-1, replacing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. TPL-005 & -006 will be addressed later in the project. Violation Risk Factors, Time Horizons, Measures, Compliance and Implementation Plans will be included in subsequent postings.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to comments from first posting of standard(s) and submit revision 1 of the standard(s).	4Q2007
2. Respond to comments from second posting of standard(s) and submit revision 2 of the standard(s).	4Q2007
3. Submit revision 3 of the standard(s) for balloting.	4Q2007
4. Submit standard(s) for recirculation balloting.	2Q2008
5. Submit standard(s) to BOT.	2Q2008
6.	
7.	

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Base Case: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect Facility Ratings.

Consequential Load Loss: Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.

Extreme Events: Events which are more severe, and have a lower probability of occurrence, than Planning Events~~ and have a low probability of occurrence~~.

Long-Term ~~Transmission~~ Planning ~~Horizon~~Assessment: ~~Transmission~~ A ~~p~~Planning Assessment period that covers years six through ten or beyond.

Near-Term ~~Transmission~~ Planning ~~Horizon~~Assessment: ~~Transmission~~ A P~~p~~lanning Assessment period that covers Years One through five.

Non-Consequential Load Loss: Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.

Planning Assessment: Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including ~~capital~~ reinforcements and operating procedures~~ and other factors, such as asset conditions and age~~.

Planning Events: Events ~~which require~~for which- Transmission system performance requirements ~~to be~~must be met.

~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~

System Stability Study: Study of the System or portions of the System to ~~ensure that~~determine whether plant and system angular Stability is maintained, ~~inter-area~~ power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.

Year One: The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner ~~submits~~completes ~~their~~ its annual studies.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-1**

3. **Purpose:** Establish Transmission System planning performance requirements ~~within the planning horizon~~ to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of ~~probable~~ possible Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator

   4.1.2. Transmission Planner

   4.1.3. Resource Planner

   4.1.4. Load-Serving Entity

   4.1.5. Transmission Owner

   4.1.6. Generator Owner

5. **Effective Date:** TBD

B. Requirements

R1. **Modeling Requirements**
Each Resource Planner, Transmission Planner, Transmission Owner, Generator Owner, and Load-Serving Entity shall each provide its respective Planning Coordinator with the following modeling information that is required for System performance studies upon request (within 30 calendar days): *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

~~**R1.1.**~~Load forecasts and Load models adhering, at a minimum, to the requirements of MOD-011 and MOD-013.~~following criteria:~~

~~**R1.2.0.**Use of expected Load mix based on the actual or expected aggregate mix of industrial, commercial, and residential Loads.~~

~~**R1.3.0.**Based on normal weather patterns as agreed to by the Planning Coordinator(s) and the Transmission Planner(s) for the area(s) of their responsibility.~~

~~**R1.4.0.**Identification of Demand Side Management (DSM) Load reductions consistent with operational requirements.~~

~~**R1.2.**~~**R1.1.** ~~Load models with supporting rationale that include power factor data that may be based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements.~~

~~**R1.3.**~~**R1.2.** Firm transfers/Interchange Schedules and resources required to supply Load for each Balancing Authority.

~~R1.4.~~R1.3. Known ~~planned outages and~~ long-term outages for Transmission and generation equipment ~~including protective relays~~ with consideration given to spare equipment ~~strategy~~.

~~R1.5.~~R1.4. Planned Facilities defined in accordance with the documented criteria of the Planning Coordinator, including but not limited to: Transmission Lines, generators, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies.

R2. **Assessment and Corrective Plan Requirements**
Each Transmission Planner and Planning Coordinator shall conduct and document the results of its annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, and shall cover steady state analyses, short circuit analyses, and Stability analyses ~~including both System and plant Stability~~. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R2.1. The steady state portion of the Near-Term ~~Transmission Planning Horizon~~ Planning Assessment shall ~~address all five years of the assessment period and~~ be conducted annually and supported ~~at a minimum~~ by ~~the following annual~~ current studies ~~, supplemented with qualified~~or past studies as ~~shown~~ indicated in Requirement R2.5~~6~~:

R2.1.1. System P~~p~~eak ~~Load~~ Demand for year five; and either Year One or year two if a significant unexpected change in the System occurs~~, and year five~~.

R2.1.2. System Off-Peak Load for one of the five years.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity ~~case(s)~~testing that stresses the System ~~with sensitivities that reflect one or more of the following conditions~~ shall be ~~run~~ considered, and documentation with the rationale for the ~~selected~~ sensitivity ~~(ies)~~testing shall be supplied.~~:~~ The sensitivity case(s) may include one or more of the following conditions:

R.2.1.3.1. Higher or lower Load forecasts from the Base Case with variability of Load~~/demand~~ and Load power factors due to season, weather, or time of day.

R.2.1.3.2. Modification of expected transfers.

R.2.1.3.3. Unavailability of planned long lead time facilities.

R.2.1.3.4. ~~Variability and o~~Outages of reactive resources.

R.2.1.3.5. Generation additions, retirements, or other dispatch scenarios.

R.2.1.3.6. Decreased effectiveness of controllable Loads and Demand Side Management.

R.2.1.3.7. A change in known long-term outages for Transmission and generation equipment, per R1.3.~~Modification of planned Transmission outages~~.

R2.2. ~~For the steady state portion of the Long-Term Transmission Planning Horizon Planning Assessment, at a minimum, a current System peak Load study is required annually for one of the years in the assessment period to support the annual Planning Assessment.~~ The steady state portion of the Long-Term Planning Assessment shall be conducted annually and supported by a System peak Load study or a past study as indicated in Requirement R2.5:

R2.2.1. If ~~To accommodate~~ any known ~~longer lead time~~ projects ~~that may take~~ have a lead time longer than ten years to complete, then the Planning Assessment shall be extended accordingly.

R2.3. The short circuit portion of the Planning Assessment shall be conducted annually and ~~shall be~~ supported by a current study or a past study as indicated in Requirement R2.5:~~ies~~.

R2.3.1. A current study shall be performed if changes in the BES result in increased fault currents such as resource additions and other facility changes that result in reductions in impedance.

R2.4. ~~The System Stability portion of the Near-Term Transmission Planning Horizon Planning Assessment shall address all five years of the assessment period and be supported by current or past studies. The following studies are required:~~ The System Stability portion of the Near-Term Planning Assessment shall be conducted annually and supported by current studies or past studies as indicated in Requirement R2.5:

R2.4.1. System P~~p~~eak ~~Load~~ Demand for one of the five years. ~~For peak System Load levels, the Load model shall include the dynamic effects of induction motor Loads.~~

R2.4.2. System Off-Peak Load for one of the five years.

R2.4.3. Sensitivity ~~case(s)~~testing that stresses the System ~~to reflect one or more of the following conditions~~ shall be ~~run~~ considered, and ~~with~~ documentation with ~~provided explaining~~ the rationale for the ~~selected~~ sensitivity testing shall be supplied~~(ies)~~. The sensitivity case(s) may include one or more of the following conditions:

R.2.4.3.1. Higher or lower Load forecasts from the Base Case with variability of Load and Load power factors due to season, weather, or time of day.

R.2.4.3.2. Modification of expected transfers.

R.2.4.3.3. Unavailability of planned long lead time facilities.

R.2.4.3.4. Outages of reactive resources.

R.2.4.3.5. Generation additions, retirements, or other dispatch scenarios.

R.2.4.3.6. Decreased effectiveness of controllable Loads and Demand Side Management.

R.2.4.3.7. A change in known long-term outages for Transmission and generation equipment, per R1.3.

~~R.2.4.3.1.~~R.2.4.3.8. -Variations in Load model assumptions.

~~R.2.5.0.0. Expected simultaneous transfers including non-firm transfers.~~

~~R.2.6.0.0. Unavailability of long lead time facilities.~~

~~R.2.7.0.0. Reactive dispatch of generators and other reactive power devices.~~

~~R.2.8.0.0. Generation additions, retirements, or other dispatch scenarios.~~

~~R2.9. The plant Stability portion of the Planning Assessment shall be analyzed consistent with Requirement R4.6 with studies for the year when the following occur:~~

~~R2.10.0. New generator(s) are added or generation modifications are made such as increasing generation capability, replacing the exciter or addition of a power System stabilizer.~~

~~R2.11.0. Material changes in the electrical vicinity of existing generation are made such as the addition or removal of a Transmission Line at or near the point of Interconnection.~~

~~R2.6.~~R2.5. Past studies may be used to support the Planning Assessment if they meet the following requirements:

~~R2.6.1.~~R2.5.1. For steady state analysis: if the study is less than ~~three~~ five years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals~~, and market structure changes~~.

~~R2.6.2.~~R2.5.2. For short circuit analysis: if the study is less than five years old and no material changes have occurred to the System in the intervening period.

~~R2.6.3.~~R2.5.3. For ~~plant and~~ System Stability analysis: until material changes in the System make the study no longer valid. Material changes in the system include the addition of a Transmission Line or a generator.

~~R2.7.~~R2.6. For Planning Events shown in Table 1 – Steady State Performance and Table 2 – Stability Performance, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans that are ~~allowed~~ made over time ~~but~~ shall meet the performance requirements in the tables. Such plans shall:

~~R2.7.1.~~R2.6.1. Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission projects and/or other changes ~~generation improvements, DSM, new technologies~~, or Operating Procedures including the duration of interim Operating Procedures.

R.2.6.1.1. For the Near-Term ~~Transmission~~ Planning ~~Horizon~~Assessment, ~~include both a project initiation date as well as an~~provide an in-service date.

R.2.6.1.2. For the Long-Term ~~Transmission~~ Planning ~~Horizon~~Assessment, provide an in-service year.

~~R2.7.2.~~R2.6.2. Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables.

~~R2.7.3.~~R2.6.3. Include documentation of the criteria for determining committed and proposed projects with all projects identified as either 'committed' or 'proposed.'

~~R2.7.4.~~R2.6.4. Not remove committed projects without documentation to show that the revised plan meets the performance requirements.

~~R2.7.5.~~R2.6.5. Be reviewed in subsequent annual Planning Assessments as to implementation status of identified System Facilities and Operating Procedures.

R3. **Steady State Analysis Requirements**

For the steady state portion of the Near-Term and Long-Term Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the ~~Near-Term and Long-Term Transmission Planning Horizon~~ studies in Requirement R2.1 and Requirement R2.2. The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to contingencies in Table 1 – Steady State Performance. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R3.1. Studies shall determine whether the BES meets the performance requirements in Table 1 – Steady State Performance.

R3.2. Contingency analyses shall simulate the removal of all elements ~~including those~~which ~~that~~ Protection Systems ~~protection is~~are expected to disconnect for each Contingency without operator intervention, and shall simulate automatic sectionalizing schemes.

~~**R3.2.1.** For all generators, studies shall consider the minimum steady state voltage limitations of all generators and identify how the generators are treated in the steady state simulation.~~

~~**R3.2.2.** For all Transmission lines, studies shall consider relay loadability and identify how loadability is treated in the steady state simulation.~~

R3.3. Studies shall identify any planned upgrades (including protection and control modifications) needed to meet the performance requirements of the Planning Events of Table 1 – Steady State Performance and validate their effectiveness.

~~R3.3.~~R3.4. For ~~S~~steady ~~S~~state studies:

~~R3.3.1.~~R3.4.1. Performance ~~criteria~~ requirements for System normal conditions and for Planning Events in Table 1 – Steady State Performance shall be met.

~~R3.3.2.~~R3.4.2. Evaluations shall be performed for single Contingencies (identified in Table 1 – Steady State Performance).

~~**R.3.3.2.1.**~~**R.3.4.2.1.** Consequential Load loss (expected maximum demand ~~and expected duration~~) following a single Contingency shall be identified in the Planning Assessment.

~~**R.3.3.2.2.**~~**R.3.4.2.2.** Following single Contingency events, System adjustments other than shedding of firm Load [this is inconsistent with Table 1 event P6] or curtailment of firm transfers[DMC1] are permitted to meet performance requirements provided these adjustments can be accomplished within the time period allowed by the applicable time limited ratings.

~~**R3.3.3.**~~**R3.4.3.** Those ~~Planning Event Contingencies in Table 1 – Steady State Performance not covered in Requirement R3.3.2~~multiple Contingencies that are expected to produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results

~~**R3.4.**~~**R3.5.** Those Extreme Events in Table 1 – Steady State Performance that are expected to produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. ~~If the Extreme Events analysis concludes there are Cascading Outages caused by the occurrence of Extreme Events, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted.~~

~~**R3.5.**~~**R3.6.** Manual and automatic generation run-back and/or generation tripping is allowed as a response to single and multiple Contingencies as long as ~~Facility Ratings are not exceeded~~the performance requirements of this standard are met.~~.~~

~~**R4.0.**Manual and automatic generation tripping is allowed for multiple Contingencies and for single Contingencies only in situations that meet all of the following conditions:~~

~~**R5.0.0.**TBD~~

~~Note: WECC has informed the SDT that it will be submitting an Interconnection-wide regional variance to allow for manual and automatic generation tripping for single Contingencies. The regional variance will be justified based on physical System differences in the western Interconnection. WECC is developing a white paper to support this position. The actual text of the regional variance will be included in the next posting of this standard.~~

R4. Stability Analysis Requirements

For the Stability portion of the Near-Term Planning Assessment, ~~as described in Requirement R2.4 and Requirement R2.5,~~ each Transmission Planner and Planning Coordinator shall perform the ~~Contingency~~ analysies for the studies as described in Requirement R2.4. The studies shall be based on computer dynamic simulations that analyze BES System response to contingencies listed in Table 2 – Stability Performance. ~~The studies shall cover both System Stability and plant Stability. The following requirements apply to both System Stability and plant Stability studies unless otherwise noted.~~ *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R4.1. Studies shall determine whether the BES meets~~to meet~~ the performance requirements in Table 2 – Stability Performance ~~shall use computer Stability simulations that analyze the response of the BES~~.

R4.2. Contingency analyses shall simulate the removal of all elements ~~including~~ which ~~those that~~ Protection Systems ~~protection is~~are expected to disconnect for each Contingency without operator intervention, and shall simulate automatic reclosing schemes.

~~**R7.3.**Studies shall consider the voltage ride through capability of all generators and identify how the generators are treated in the simulation.~~

~~**R4.4.**~~**R4.3.** Studies shall identify any planned upgrades (including protection and control modifications) needed to meet the performance requirements of the Planning Events of Table 2 – Stability Performance and validate their effectiveness.

~~**R4.5.**~~**R4.4.** For the System Stability S~~s~~tudy:

~~**R4.5.1.**~~**R4.4.1.** ~~At a minimum,~~T~~t~~hose Planning Events ~~Contingencies~~ in Table 2 – Stability Performance that ~~would~~ are expected to produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results.

~~**R4.5.2.**~~**R4.4.2.** ~~At a minimum,~~T~~t~~hose Extreme Events in Table 2 – Stability Performance that are expected to ~~would~~ produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. ~~If the Extreme Events analysis concludes there are Cascading Outages, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted.~~

~~**R8.**For the Plant Stability studies:~~

~~**R9.**Shall be performed for individual generating units 20 MW or greater directly connected through a step-up transformer to the BES and for generating units at the same location which total 75 MW or greater, directly connected through their step-up transformer(s) to the BES.~~

~~**R10.**Shall be performed for changes in the real power output of a generating unit by more than 10% of the existing capability or more than 20 MW whichever is greater.~~

~~**R11.**Shall be performed and evaluated for those Planning Events that would produce more severe System impacts shall be identified and the rationale for the Contingencies~~

~~selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. The identified Contingencies, at a minimum, shall be evaluated.~~

~~**R12.**Shall meet Performance requirements for Planning Events in Table 2 – Stability Performance.~~

R5. Each Transmission Planner and Planning Coordinator shall determine and identify individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R6. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among affected entities, coordinating analysis of these results through an open and transparent peer review process. *[Violation Risk Factor: TBD] [Time Horizon: TBD]* This distribution shall include:

R6.1. Transmission Planners within the Planning Coordinator's area

R6.2. Transmission Planners of neighboring impacted areas

R6.3. Planning Coordinators of neighboring impacted areas

Table 1 – Steady State Performance

Performance Requirements

For all Planning Events:

- Equipment Ratings shall not be exceeded
- System steady state voltages and post-transient voltage deviation shall be within acceptable limits established by the Planning Coordinator (or Transmission Planner if more restrictive)
- Voltage instability, cascading outages, and uncontrolled islanding shall not occur
- Consequential Load loss is allowed for all cases shown.
- Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency.
- Simulate Normal Clearing unless otherwise specified.

Planning Events

#	Event	Interruption of Firm Transfer Allowed (does not result in loss of Load)	Non-Consequential Load Loss Allowed
P0	All transmission facilities in service	No	No
P1 (single Contingency)	Loss of: **1.** A generator **2.** A Transmission circuit **3.** A transformer 4. A shunt device (including FACTS devices)	Yes, if transfer is dependent on the outaged element No otherwise	No
P2 (single Contingency)	Loss of: 1. Bus section above 300kV 2. ~~Non-bus tie b~~Breaker (above 300kV) due to internal fault ~~3.~~Single pole of a DC line 3.	Yes, if transfer is dependent on the outaged ~~DC line~~element No otherwise	No
P3 (multiple Contingency)	Loss of either a: 1. A generator, 2. A Transmission circuit, 3. A~~a~~ transformer with low side voltage rating above 300 kV, or 4. A~~a~~ bus; **and** ~~-~~a stuck ~~non-bus tie~~ breaker (above 300kV)	Yes, if transfer is dependent on the outaged ~~DC line~~element No otherwise	No
P4 (multiple Contingency)	1. Loss of a generator followed by a System adjustment followed by the loss of a generator. 2. Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line 3. Loss of a generator followed by a System adjustment followed by the loss of a Transmission circuit	Yes, if transfer is dependent on the outaged ~~DC line~~element No otherwise	~~No~~Yes

	4. Loss of a generator followed by a System adjustment followed by the loss of a transformer		
P5 (multiple Contingency)	Above 300kV, the loss of: 1. A Transmission circuit followed by a System adjustment followed by the loss of another Transmission circuit 2. A Transmission circuit followed by a System adjustment followed by the loss of a transformer with low side voltage rating above 300 kV 3. A transformer with low side voltage rating above 300 kV followed by a System adjustment followed by the loss of another transformer	Yes	~~No~~Yes
P6 (single Contingency)	Loss of: 1. A ~~bus tie~~ breaker due to internal fault 2. A bipolar DC line or an asynchronous ~~tie line~~interconnection 3. A ~~non-bus tie~~ breaker (below 300kV) due to internal fault 4. A bus section below 300kV	Yes	Yes
P7 (multiple Contingency)	Loss of: 1. A bus section above 300kV and a stuck ~~bus tie~~ breaker 2. Either a generator, a Transmission circuit, a transformer, or a bus and a stuck ~~non-bus tie~~ breaker (below 300kV)	Yes	Yes
P8 (multiple Contingency)	Below 300kV, the loss of: 1. A Transmission circuit followed by a System adjustment followed by the loss of another Transmission circuit 2. A Transmission circuit followed by a System adjustment followed by the loss of a transformer 3. A transformer followed by a System adjustment followed by the loss of another transformer	Yes	Yes
P9 (multiple Contingency)	1. Loss of any two circuits on a common structure (excluding where multiple circuits share a common structure for no more than one mile) 2. Loss of a generator followed by a System adjustment followed by the loss of a monopolar or bipolar DC line, or an asynchronous ~~tie line~~interconnection 3. Loss of a DC line (monopolar or bipolar) or asynchronous ~~tie~~ interconnection followed by a System adjustment followed by the loss of a second DC line (monopolar or bipolar) or asynchronous ~~tie~~ interconnection 4. Loss of a DC line (monopolar or bipolar) or asynchronous ~~tie~~ interconnection followed by a System	Yes	Yes

	adjustment followed by the loss of a Transmission circuit 5. Loss of a transformer followed by a System adjustment followed by the loss of a DC line (monopolar or bipolar) or asynchronous ~~tie line~~interconnection 6. Loss of a transformer followed by a System adjustment with a spare transformer available followed by the loss of another transformer		

Extreme Events

Evaluation Requirements

For all Extreme Events:

1. See Requirement R3.~~5~~4
2. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency.
3. Simulate Normal Clearing unless otherwise specified.

Extreme Event Descriptions

1. Loss of a single generator, Transmission circuit, DC line, or transformer forced out of service followed by another single generator, Transmission circuit, DC line, or transformer forced out of service prior to System adjustments.

2. Local area events affecting the Transmission System such as:
   - **a.** Loss of tower line with three or more circuits
   - b. Loss of all Transmission lines on a common right-of-way
   - c. Loss of switching station or substation (loss of one voltage level plus transformers)
   - d. Loss of all generating units at a station
   - **e.** Loss of a large Load or major Load center

3. Wide area events affecting the Transmission System such as:
   - a. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation
   - ~~b.A successful cyber attack~~
   - ~~c.Regulation that restricts or eliminates the use of a river or lake or other body of water as the cooling source for generation~~
   - ~~d.Shutdown of a nuclear power plant(s) and other facilities a day or more prior to a hurricane, tornado or wildfire, or for other common causes~~
   - ~~e.Regulation that restricts or eliminates the use of a river or lake or other body of water as the cooling source for generation~~
   - ~~f.~~b. Shutdown of a nuclear power plant(s) and other facilities a day or more prior to a hurricane, tornado or wildfire, or for other common causes such as problems with similarly designed plants
   - ~~g.~~c. The loss of older Transmission lines which may not be constructed to meet an entity's present radial ice or wind loading requirements, while the newer or stronger Transmission lines remain in service
   - ~~h.~~d. Other events based upon operating experience

Table 2 – Stability Performance Table

Performance Requirements			
For all Planning Events: • The System shall be stable¹ • Dynamic voltages shall be within acceptable limits established by the Planning Coordinator or Transmission Planner (if more restrictive) • Uncontrolled islanding and Cascading Outages shall not occur • Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency. • Simulate permanent Faults with Normal Clearing unless otherwise specified.			
Planning Events			
#	**Initial Condition**	**Event**	**Non-Consequential Load Loss Allowed**
P1 (single Contingency)	System normal	Single Line Ground (SLG) fault on, a 3-Phase (3Ø) fault on, or an unexpected loss without a fault of (whichever is worst): 1. A generator 2. A Transmission circuit ~~3.~~3. A transformer	No
P2 (single Contingency)	System normal	1. SLG fault on bus section above 300kV 2. SLG internal fault in ~~non-bus tie~~ breaker (above 300kV) 3. A single pole block of a DC line	No
P3 (multiple Contingency)	System normal	SLG fault on either a 1. A generator, 2. A Transmission circuit, 3. A~~a~~ transformer, or 4. A~~a~~ bus **and** a stuck[2] ~~non-bus tie~~ breaker (above 300kV)[DMC2]	No
P4 (multiple Contingency)	A single generator out of service followed by System adjustments	1. Apply a P1.1 Contingency. 2. Apply a P2.3 Contingency. 3. Apply a P1.2 Contingency. 4. Apply a P1.3 Contingency.	No
P5 (multiple Contingency)	A Transmission circuit above 300 kV out of service followed by System adjustments A transformer with low side voltage rating above 300 kV	1. Apply a P1.2 Contingency. 2. Apply a P1.3 Contingency. 3. Apply a P1.3 Contingency.[DMC3]	No

	out of service followed by System adjustments		
P6 (single Contingency)	System normal	1. SLG internal fault in ~~bus tie~~ breaker 2. A bipolar block of a DC line ~~1.~~3. SLG internal fault in ~~non-bus tie~~ breaker (below 300kV) 4. SLG fault on bus section (below 300kV)	Yes
P7 (multiple Contingency)	System normal	1. SLG fault on a bus section above 300kV and a stuck ~~bus tie~~ breaker 2. SLG fault on either a generator, a Transmission circuit, a transformer, or a bus and a stuck ~~non-bus tie~~ breaker (below 300kV)	Yes
P8 (multiple Contingency)	A Transmission circuit below 300 kV out of service followed by System adjustments A transformer with low side voltage rating below 300 kV out of service followed by System adjustments	1. Apply a P1.2 Contingency. 2. Apply a P1.3 Contingency. 3. Apply a P1.3 Contingency. [DMC4]	Yes
P9 (multiple Contingency)	System normal A single generator out of service followed by System adjustments A DC circuit out of service followed by System adjustments A transformer out of service followed by System adjustments	1. SLG fault on each circuit of ~~any~~ two adjacent circuits on a common structure (excluding events where multiple circuits share a common structure for no more than one mile). 2. Apply a P6.2 Contingency. 3. Apply a P2.3 Contingency. 4. Apply a P1.2 Contingency. 5. Apply a P2.3 Contingency.	Yes

	A spare transformer inserted to replace an outaged transformer followed by System adjustments	6. Apply a P1.3 Contingency. [DMC5]	

Extreme Events

Evaluation Requirements

For all Extreme Events:

- See Requirement R4.~~5~~4.2 in the text
- Simulate the removal of all elements that Protection Systems ~~protection~~ and controls are expected to disconnect for each Contingency.
- Simulate Normal Clearing unless otherwise specified.

Extreme Event Descriptions

1. 3Ø fault on generator with stuck breaker
2. 3Ø fault on Transmission circuit with stuck breaker
3. 3Ø fault on transformer with stuck breaker
4. 3Ø fault on bus section with stuck breaker
5. 3Ø internal fault in breaker
6. 3Ø fault on two or more circuits on a common structure
7. SLG or 3Ø fault on all Transmission lines on a common right-of-way
8. 3Ø fault on switching station or substation (loss of one voltage level plus transformers)
9. 3Ø fault with loss of all generating units at a station

Notes:

1. System stable means:
    a. Angular stability:
        i. For Planning Events P1 and P3.2: No generating unit or units shall be allowed to pull out of synchronism. A generator being disconnected from the system by fault clearing action or by a Special Protection ~~Scheme~~ System is not considered pulling out of synchronism.
        ii. For all other Planning Events: No generating unit or units totaling more than the contingency reserve (spinning reserve) of the Balancing Authority shall be allowed to pull out of synchronism. Generators that pull out of synchronism must have ~~out-of-step protection and the~~ resulting apparent impedance swings ~~must~~ that do not pass through relay characteristics that would result in the tripping of any T~~t~~ransmission system elements other than the generating unit and its direct connection facilities.

iii. For all Planning Events: Power oscillations shall exhibit acceptable damping~~ as established by the Planning Coordinator or Transmission Planner (if more restrictive)~~.

b. General: Unplanned islanding of portions of the system shall not occur for Planning Events.

2. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) breaker, only one pole is assumed to remain closed.

~~3.~~C. Measures

M1. To be supplied at a later date.

E. Regional Variances

1. WECC Interconnection-wide waiver is under development (see Requirement R3.6.2).

Version History

Version	Date	Action	Change Tracking
1		Revision of TPL-001-0 as per Project 2006-02; includes merging requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-1	Not employed due to scope of revision

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

<table>
<tr><th colspan="3">Individual Commenter Information
(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td>Name:</td><td colspan="2">Jeff Knottek</td></tr>
<tr><td>Organization:</td><td colspan="2">City Utilities of Springfield, Missouri</td></tr>
<tr><td>Telephone:</td><td colspan="2">417-831-8920</td></tr>
<tr><td>E-mail:</td><td colspan="2">jeff.knottek@cityutilities.net</td></tr>
<tr><th>NERC Region (check all Regions in which your company operates)</th><th></th><th>Registered Ballot Body Segment (check all industry segments in which your company is registered)</th></tr>
<tr><td rowspan="10">☐ ERCOT
☐ FRCC
☐ MRO
☐ NPCC
☐ RFC
☐ SERC
☒ SPP
☐ WECC
☐ NA – Not Applicable</td><td>☒</td><td>1 — Transmission Owners</td></tr>
<tr><td>☐</td><td>2 — RTOs and ISOs</td></tr>
<tr><td>☒</td><td>3 — Load-serving Entities</td></tr>
<tr><td>☐</td><td>4 — Transmission-dependent Utilities</td></tr>
<tr><td>☐</td><td>5 — Electric Generators</td></tr>
<tr><td>☐</td><td>6 — Electricity Brokers, Aggregators, and Marketers</td></tr>
<tr><td>☐</td><td>7 — Large Electricity End Users</td></tr>
<tr><td>☐</td><td>8 — Small Electricity End Users</td></tr>
<tr><td>☐</td><td>9 — Federal, State, Provincial Regulatory or other Government Entities</td></tr>
<tr><td>☐</td><td>10 — Regional Reliability Organizations and Regional Entities</td></tr>
</table>

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: The manner in which the forecasted bus load is determined needs to be defined with clear and consistent assumptions and methodologies such that the results of transmission studies are reasonably valid throughout the entire planning horizon.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	

Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☐Do not agree.
Q7. **Comment: : Definition should be more clearly defined. Documented evaluation of future Bulk Electric System needs based on the performance requirements as defined for NERC Steady State Transmission Studies or Plant Stability Studies conducted in accordance with the NERC Reliability Standards or more restrictive local area criteria.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Minimum performance requirements need to be clearly defined.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the

rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☒ No ☐
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☒ No ☐
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: : Controllable demand that will be available to both the planner and operator must be well defined and readily available when called upon including operating procedures.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐

Comment: : Corrective action plans must be appropriately modeled in order to verify that implementing the plans results in a BES that will perform based on the applicable NERC Reliability Standards or more restrictive local area criteria.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐

Comment: : Definitions of both “committed” and “proposed” are needed.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐

Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to “raise the bar.” Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☐Do not agree.	Would like to see more explanation for the these scenarios.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

[1] System adjustment can be manual or automatic

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: Requirement R3.2: Contingency analyses representing only the removal of elements that System protection is expected to automatically disconnect which includes Consequential Load Loss is a reduction in reliability. Excluding the contingency analyses between all elements including those with manually operated switches will result in lowering existing reliability standards and ultimately limit the load restoration capabilities of the BES. Minimum performance standards should be adhered to for all applicable contingencies including outages of elements that may be switched both automatically and manually taking into account controlled load curtailment that is allowed.
Requirement R3.3.2.1: The expected duration of Consequential Load Loss was noted to be required in a Planning Assessment following a single Contingency without any indication as to the assumed cause of the outage. The basis for such estimations of time needs to be defined such that these assessments are developed on a consistent basis.

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**	
Name:	Karl Kohlrus
Organization:	City Water, Light & Power - Springfield, Illinois
Telephone:	217-321-1391
E-mail:	karl.kohlrus@cwlp.com

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☒	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: This should not be a defined term in the Glossary, instead there should be a Standard that provides the industry with the requirements for completing a Base Case Study.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment: This could be load lost which is on a radial line or load served by facilites which do not have fault-interrupting breakers.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: More needs to be added here, especially to define the phrase "low probability of occurrence". Does this refer to N-1, N-2, N-3 etc.? We have a 300 foot long interconnection line between two substations. In this case even N-1 has a low probability of occurrence. This N-1 event has a much lower probability of occurrence than an N-2 event which involves generator outages. We also have an N-1 SPS event which hasn't occurred in 25 years.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	

Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: This definition should go beyond just saying "Load loss other than Consequential Load Loss." Recommend adding the following: " . . . including Load Loss that occurs through planned manual (Transmission Operator, Distribution Provider, and so-on) operation or planned automatic operation of load shedding equipment such as under-frequency Load shedding devices or Special Protection Systems."**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: This definition is too vague. A Planning Assessment should cover the Near-Term or Long-Term Planning Horizon and include Base Case and Contingency Analysis according to NERC Standards.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: This statement is too general. Performance Requirements are not defined.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Insert "Generating" prior to "Plant" for clarity.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of

variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☒ No ☐

Comment: The term Base Case should not be used in this manner. The conditions of the Base Case Study should be in a Standard to insure that all sensitivity cases are covered.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☒ No ☐

Comment: The Standard should indicate a list which says "the list will include but not be limited to:" then list the minimum changes necessary to adequately cover the changes in the study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒

Comment: The requirement for sensitivity studies multiplies the study efforts. It will be burdensome especially when interregional studies are performed. It is better to have quality than quantity.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒
Comment: DSM is not always available and is usually not available without operator action. Therefore, asuming it is alwasys available could give a false sense of security. The system could collapse before DSM is able to be implemented..

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: The system should be retested with new facilities in place to ensure that no new problems arise with the addition of new facilities.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: "Committed" and "proposed" projects need to be defined.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed	☒Agree. ☐Do not agree.	

by System adjustment followed by loss of another transformer		

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	

[1] System adjustment can be manual or automatic

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment: If there is any single contingency event that could take out an entire plant, it should be studied.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: However, low voltage often causes motors and air conditioner compressors to trip, significantly reducing peak loads.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Dispatching quick start units such as combustion turbines or diesels, Contingency Reserve Sharing Group response, redispatch, adjust reactive resources as necessary.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Coordination with neighboring systems is essential when considering generation redispatch.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☒
Comment: SPS use should be limited and SPS's should be of a temporary nature. A mitigation plan with a timeframe for implementation should accompany all SPS's and RAS's.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: See above.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: Maintain system stability, prevent loss of load and prevent cascading outages.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☐ No ☐
Comment: The Standards are a great start in getting a set of requirements in place that will provide a planning methodology that will be transparent to the Functional entities in the interconnections and will produce results that will permit reliable planning and operations of the BES.
The SDY should remove all Requirements that are subjective and can't be measured.
The assumptions the Transmission Planners and Planning Coordinators use to conduct the studies should be posted.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)	
Name:	Blake Williams
Organization:	CPS Energy
Telephone:	210-353-3557
E-mail:	bawilliams@cpsenergy.com

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☒ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: Firm transaction obligations are not used throughout all regions in NERC. Change "including firm transaction obligations" to "including firm transaction obligations where applicable."**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	

Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☐Do not agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.

- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: The number of sensitivity studies should be at the discretion of Transmission Planners.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: The type of sensitivty studies should be at the discretion of Transmission Planners.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒
Comment: The number and type of sensitivity studies should be at the discretion of Transmission Planners.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☒
Comment: We concur with not requiring sensitivity studies for the Long Term Assessment.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in

conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒

Comment: Performance of the DSM is not necessarily controlled by the Transmission Owner and cannot be considered "firm". Therefore, use of DSM should be optional, but not mandated.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒

Comment: Should be conducted for Near Term Planning Assessment only with the study area determined at the discretion of the Transmission Planners.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒

Comment: The treatment of each project should be at the dscretion of the Transmission Planners.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒

Comment: The treatment of each project should be at the discretion of the Transmission Planners.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Should be determined at the discretion of the Transmission Planners.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: Should be determined at the discretion of the Transmission Planners.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: Should be determined at the discretion of the Transmission Planners.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	Should be determined at the discretion of the Transmission Planners.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	Should be determined at the discretion of the Transmission Planners.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	Should be determined at the discretion of the Transmission Planners.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

[1] System adjustment can be manual or automatic

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☒
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:

R1.1. This is a modeling requirement and should be incorporated into the modeling (MOD) standards. Remove or modify this requirement to eliminate any redundancy with existing modeling standards. If certain subrequirements of R1.1 of TPL-001 are not currently requirements in a MOD standard, it should be questioned, then, whether or not these specific subrequirements are actually needed in ANY standard.

R2.2. ERCOT does not study the Long-Term Planning Horizon because ERCOT does not believe it is necessary. Remove or modify to state "as applicable by region."

R2.7.1.1 Duration of projects vary between Transmission Owners and statement of the project initiation date has no value to reliability.

R3.3.2 Relay loadability is considered as an MLSE component to the circuit rating as identified in MOD-008 and MOD-009.

R3.3.2.1. The requirement to identify consequential load loss for single contingencies in the Planning Assessment is unnecessary and burdensome and should be removed.

R3.6 Automatic generation tripping should be allowed for radial-connected wind resources.

Table 1 - P6.1, P6.3, and P6.4 These events are triggered by a single credible event and should not allow for loss of Non-Consequential Load.

Table 1 - P9.1 Loss of double-circuit tower lines are triggered by a single credible event and should not allow for loss of Non-Consequential Load.

Table 1 and Table 2 - P4, P5, P8, and P9. Including all combinations of two components (generator, Transmission circuit, transformer) with generation adjustments is impractical and overly burdensome. For multiple contingencies, include only double-circuit tower lines and the two components (generator, Transmission circuit, transformer) that would be cleared by breaker failure.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

<table>
<tr><th colspan="3">Individual Commenter Information
(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td colspan="3">Name:</td></tr>
<tr><td colspan="3">Organization:</td></tr>
<tr><td colspan="3">Telephone:</td></tr>
<tr><td colspan="3">E-mail:</td></tr>
<tr><td>NERC Region (check all Regions in which your company operates)</td><td></td><td>Registered Ballot Body Segment (check all industry segments in which your company is registered)</td></tr>
<tr><td rowspan="10">☐ ERCOT
☐ FRCC
☐ MRO
☐ NPCC
☐ RFC
☒ SERC
☐ SPP
☐ WECC
☐ NA – Not Applicable</td><td>☒</td><td>1 — Transmission Owners</td></tr>
<tr><td>☐</td><td>2 — RTOs and ISOs</td></tr>
<tr><td>☐</td><td>3 — Load-serving Entities</td></tr>
<tr><td>☐</td><td>4 — Transmission-dependent Utilities</td></tr>
<tr><td>☐</td><td>5 — Electric Generators</td></tr>
<tr><td>☐</td><td>6 — Electricity Brokers, Aggregators, and Marketers</td></tr>
<tr><td>☐</td><td>7 — Large Electricity End Users</td></tr>
<tr><td>☐</td><td>8 — Small Electricity End Users</td></tr>
<tr><td>☐</td><td>9 — Federal, State, Provincial Regulatory or other Government Entities</td></tr>
<tr><td>☐</td><td>10 — Regional Reliability Organizations and Regional Entities</td></tr>
</table>

Group Comments (Complete this page if comments are from a group.)

Group Name: **Dominion - Electric Transmission Planning**

Lead Contact: **John K. Loftis, Jr.**

Contact Organization: **Dominion Virginia Power**

Contact Segment: **1**

Contact Telephone: **(804) 819-2337**

Contact E-mail: **john.loftis@dom.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
Kirit Doshi	Dominion - Electric Transmission Interconnection Planning	**SERC**	1
Craig Crider	Dominion - Electric Transmission Interconnection Planning	SERC	1
Solomon Yirga	Dominion - Electric Transmission Interconnection Planning	SERC	1
Nelson Burks	Dominion - Electric Transmission Interconnection Planning	SERC	1
Ashwani Vaswani	Dominion - Electric Transmission Load Planning	SERC	1
Mehdi Shakibafar	Dominion - Electric Transmission Interconnection Planning	SERC	1
Abdur Masood	Dominion - Electric Transmission Operations Planning	SERC	1
Thanh Nguyen	Dominion - Electric Transmission Operations Planning	SERC	1
Ed Croasdale	Dominion - Electric Transmission Operations Planning	SERC	1
Al MacDonald	Dominion - Electric Transmission Operations Planning	SERC	1

William Bigdely	Dominion - Electric Transmission Load Planning	SERC	1
Ronnie Bailey	Dominion Manager - Electric Transmission Planning	SERC	1

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than	☒Agree.

Planning Events and have a low probability of occurrence.	☒Do not agree.
Q3. **Comment: To make this "crisp", it is suggested that this definition be extended as "Events which …..occurrence. The Transmission system performance requirements do not apply to extreme events".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☒Do not agree.
Q7. **Comment: Suggest to change "…by the use of performance studies that cover……" to "…by the use of past or current performance studies that cover……".**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the	☒Agree. ☐Do not agree.

study publication are assumed to be conducted under the auspices of Operations Planning.	
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: Transmission Planning engineers have good engineering judgment and need to have some flexibility in selecting the variables that need to be studied.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: Transmission Planning engineers have good engineering judgment and need to have some flexibility in selecting the variables that need to be studied.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒

Comment: Not all the items listed under "B. Sensitivity Studies" may be applicable to stability analysis and also depends on type of stability analysis (Plant/System; angular/voltage). For instance, in some locations stability margins are wide. In such cases, practical experience has shown that such sensitivity analysis is unnecessary. Therefore, this should be applied as applicable, at the engineering judgment of the planning engineers rather than be required by the Standards. In summary, R2.4.3 should be eliminated entirely.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: We concur that no sensitivity studies should be required for the LT planning horizon.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: An appropriate level of DSM should be included in studies.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒
Comment: In the normal course of business, a planner out of necessity will need to check to see if the proposed improvements will actually fix the problem. The prospect of making a multi-million dollar mistake is sufficient incentive to insure this study occurs without the additional burden of creating an audit trail to meet a NERC standard.

Requirements for what study area should be used and documentation of the process are not necessary. If, per chance, a study is not performed immediately, the next set of studies will show the deficiencies, if any.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐

Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒

Comment: We are of the opinion that committed projects could be removed without documentation. Once a project is removed, the next set of studies will show the deficiencies, if any.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for	☐Agree.	Usually, this type of outage will not involve non-consequential load loss,

stability) above 300 kV	☒Do not agree.	however, there may be specific situations where local non-consequential load loss could be justified. This is consistent with how transmission systems have been designed for many years and approved by State commissions. Transmission Owners need to have some flexibility to balance grid reliability vs. cost to the ratepayer. In some instances, the expense required to eliminate all local non-consequential load loss cannot always be justified if there is no significant improvement in wide area bulk power system reliability. In other words, making the standards more stringent by "raising the bar" is not going to result in a dramatic improvement in system reliability. Even the best designed systems are susceptible to human error. Dominion has at least 5 years of transmission outage data clearly illustrating that any resulting loss of load (both consequential and non-consequential) has had an average duration of only 4-7 customer-minutes per year. Going forward, the emphasis and focus should be on planning and operating the bulk electric system so as to confine any transmission outages to the immediate, local area, and not allow the cascading of outages beyond control area boundaries.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	See comment for Question 20 above.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	See comment for Question 20 above.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment	☐Agree. ☒Do not agree.	See comment for Question 20 above.

followed by loss of another transformer		

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: See comment for Question 20 above.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: See comment for Question 20 above.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	Dominion agrees with these proposed standards as they are relatively higher probability events and reflect very closely to the Company's internal planning criteria.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	Although we do not have any DC lines, Dominion agrees with these proposed standards as they are relatively higher probability events and reflect very closely to the Company's internal planning criteria.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	Dominion agrees with these proposed standards as they are relatively higher probability events and reflect very closely to the Company's internal planning criteria.
Q29. P4-4: Loss of a generator followed by System adjustment followed	☒Agree. ☐Do not agree.	Dominion agrees with these proposed standards as they are relatively higher probability events and reflect very

[1] System adjustment can be manual or automatic

by loss of a transformer with low side voltage rating above 300 kV		closely to the Company's internal planning criteria.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment: Not applicable since Dominion has no DC lines

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: More clarification is needed to distinguish the difference in studies performed for plant stability vs. system stability. For example, is a system study mainly a study of inter-area (i.e. - small signal) oscillations?

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: It is unlikely that all units at a plant would trip simultaneously within a short time frame (20 second or so) for which stability simulations are performed.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☒
Comment: The dynamic effects of induction motor load at peak load conditions should be studied only on a limited/selected basis and should not be required for the entire system as a routine study practice. The following are examples where such an effort might be warranted:

(a) where slow voltage recovery has been actually observed in the field following a fault clearance
(b) where steady state analysis (P-V & Q-V curves) indicates a possible voltage collapse scenario for stressed system conditions
(c) for a non-convergent (or very difficult to solve) power-flow case for stressed system conditions while solving for a contingency scenario

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: For a single contingency, no generation adjustment should be allowed. For multiple transmission element contingencies, generation reduction (automatic or manual runback) may be allowed. Unit trip should only be allowed if a unit becomes unstable.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☒
Comment: For a single contingency, no generation adjustment should be allowed. For multiple transmission element contingencies, generation reduction (automatic or manual runback) may be allowed. Unit trip should only be allowed if a unit becomes unstable.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☒
Comment: For a single contingency, no generation adjustment should be allowed. For multiple transmission element contingencies, generation reduction (automatic or manual runback) may be allowed. Unit trip should only be allowed if a unit becomes unstable.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: For single contingency events, a SPS scheme should not result in loss of load.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☒ No ☐
Comment: Current planning criteria are approved by State commissions. It is unlikely that the commissions would agree that rate payers should incur the significant cost increases required to meet more stringent planning criteria (i.e. - "raising the bar") when the corresponding improvements in transmission system reliability cannot be quantified.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:

GENERAL COMMENTS:

(1) Making the standards more stringent by "raising the bar" is not going to result in a dramatic improvement in system reliability. Even the best designed systems are susceptible to human error. Dominion has at least 5 years of transmission outage data clearly illustrating that any resulting loss of load (both consequential and non-consequential) has had an average duration of only 4-7 customer-minutes per year. Going forward, the emphasis and focus should be on planning and operating the bulk electric system so as to confine any transmission outages to the immediate, local area, and not allow the cascading of outages beyond control area boundaries.

(2) Although we are unable to put specific numbers on the impact of "raising the bar "with respect to non-consequential load loss, it will be enormous. Increased staffing levels may be required, and we would likely incur significant increased transmission maintenance and construction costs. It is likely that State commissions everywhere (not just Virginia) would agree that rate payers should not incur the significant cost increases required to meet more stringent planning criteria (i.e. - "raising the bar") when the corresponding improvements in transmission system reliability cannot be quantified.

SPECIFIC COMMENTS PERTAINING TO REFERENCED SECTIONS OF THE STANDARD:

(1) The last block in Category C of Table 1 of the existing standards deals with protection system failure. We interpreted this as, among other things, having a fault beyond the first-zone coverage of the primary protection scheme with the carrier equipment failure resulting in a second-zone trip of the faulted line (even though only one element will be lost). The second-zone trip time is generally in the range of 30-35 cycles. This may be critical from the stability aspect. The proposed Table 2 of TPL-001-1 is silent about this. Is there a reason why this requirement was left out?

(2) The requirement R4.6.2 may cause some confusion due to the last part "….whichever is greater". It is suggested that the entire wording for this requirement be replaced as listed below to avoid any misunderstanding.

"Shall be performed for changes in the real power output of a generating unit if either of the following applies:
(a) the increase is more than 10 % of the existing capacity (regardless of the amount of MW increase)
(b) the increase is more than 20 MW (regardless of the % increase).

Something to think about regarding a cut-off limit of 10% or 20 MW:

We had a unit with 800 MW existing capacity and the request was to increase it by 15 MW making the total new capacity of 815 MW. The requested increase was less than 10% of the existing capacity and also less than 20 MW, meaning the plant stability study is not required. However, we found that the increase of 15 MW made the plant unstable and we had to come up with a solution (and we did). This example warrants to include something like…. "However, in cases where a stability margin is known (or estimated) to be slim, stability study should be performed regardless of the % or MW amount of increase (this leads to defining "Stability Margin").

(3) Table I, bullet 3 states that "Voltage Instability, cascading outages and uncontrolled islanding shall not occur." There is no definition for "voltage instability" anywhere in the proposed standard.

(4) R.3.3.2.1. states "Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment." This requirement creates significant unnecessary work without adding any value to system reliability.

(5) Extreme Event Description 3.d. states: "Shutdown of a nuclear power plant(s) and other facilities a day or more prior to a hurricane, tornado or wildfire, or for other common causes." It would appear that day ahead planning for a tornado is not possible, or applicable, for inclusion in this listing.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Greg Rowland	
Organization:	Duke Energy	
Telephone:	704-382-5348	
E-mail:	gdrowland@duke-energy.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☐	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: It is unclear what is meant by "mis-operation". The SDT also needs to address load lost during the transient time frame (e.g. load dropout due to low voltages as a result of a fault) that may not be directly connected to the element removed from service.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	

Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☐Do not agree.
Q7. **Comment: We have a concern with what will be considered acceptable documentation, particularly as it relates to asset conditions and age. Delete the word "needs" and the phrase "such as asset conditions and age". When measures are developed it should be made clear what will constitute an acceptable Planning Assessment.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Delete the term "the effect on the System of." The reference to "System" causes confusion with the term "System Stability Study.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: Need to provide an example to clarify what this means.**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the

rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: The entity performing the studies has the best system specific knowledge to select the appropriate sensitivities that needs to be evaluated. When Measures are developed, they should provide planners with the flexibility to perform appropriate sensitivity studies.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a “reasonably stressed” case?

Yes ☐ No ☒
Comment: The sensitivities are best selected by those most familiar with the specific system.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☒
Comment: Sensitivity studies can be useful, but they should only be requried for System Stability Studies. Due to the intensive nature of the studies, the planning engineer should have flexibility to determine appropriate sensitivities to analyze.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: Agreed, sensitivity studies should not be required for the Long-Term.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: DSM should be carefully included based upon consideration of the particular DSM measures available and the uncertainty associated with each.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐

Comment: New studies should be performed, but the study conditions should be determined based upon the judgment of the planner.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒

Comment: Even committed projects may not be built due to a variety of circumstances. Either type of project can be deferred or cancelled for a variety of reasons, including circumstances beyond the transmission planner's control.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒

Comment: The annual assessment will show that the revised plan meets performance requirements.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to

clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Allow indirect (Non-Consequential) loss of load for events involving short duration outages, such as typical line outages that do not result in cascading outages.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Allow indirect (Non-Consequential) loss of load for events involving short duration outages, such as typical line outages that do not result in cascading outages.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	Allow indirect (Non-Consequential) loss of load for events involving short duration outages that do not result in cascading outages.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒

Comment: Depends upon the definition of non-bus tie breaker. By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with	☒Agree. ☐Do not agree.	Table in TPL-001-1 doesn't include the last part of P4-4 (low side voltage rating above 300 kV). We assume the inclusion of 300kV here in the comment

[1] System adjustment can be manual or automatic

low side voltage rating above 300 kV		form is in error.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒
Comment: DC and AC line contingencies should have the same requirements.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: We agree with the basis laid out (in the question) by the SDT.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: In general, it is a good practice for System Stabilty studies of seasonal load conditions to include the effects of induction motors. However, there is currently a lack

of data to support the amount and characteristics of detailed induction load models in many areas. Prior to making this a requirement, the industry needs guidance as to how this data should be developed, shared and maintained for near-term and long-term models. A long term transition period is required to incorporate motor models into dynamics studies.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: This question is not clear. Manual and automatic adjustments should be allowed for single and multiple contingencies as long as Performance Requirements are met.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: We see this as an acceptable form of manual or automatic redispatch, which should be allowed as a cost beneficial way of operating the system in a reliable manner, as long as it can be accomplished within the time frame before emergency ratings are exceeded.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☒
Comment: Runback should not be used if the disturbance caused you to exceed emergency ratings (i.e. thermal overload).

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: RAS and SPS are economical solutions that planners ought to be able to use.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: You should not have any wide area cascading if the RAS or SPS fails to operate as expected, or operates when it shouldn't.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: See response to Q36 and Q37 above. No additional conditions beyond meeting the performance requirements.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☐ No ☒
Comment:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☒ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☒	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: Why define a term that is used only once in the document (R.2.1.2.1) and is, by definition, applicable to a[ny] specific point in time.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: I agree with the definiton except for "or mis-operation". The requirements do not, and should not, include mis-operation of protection schemes. We would never finish a study of all potential mis-operations.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: I disagree with the phrase "and have a low probability of occurance". All the Planning Events, except possibly a generator outage (P1.1), have a low probability of occurance.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such	☒Agree. ☐Do not

as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: I agree that Asset Managers need to consider asset condition and age in their spare equipment and replacement strategies but the impact of these factors is beyond the scope of a deterministic Planning Assessment.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Recommend: Events to be simulated is studies (listed in Tables 1 and 2 of TPL-001) which must be documented with Corrective Action Plans when performance requirements of TPL-001 are not met.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: "studies" should be replaced with "Planning Assessemt", the Planning Assessement is the documention (of past and current studies) submitted for review. Note: the definiton in Q11 does not match TPL-001.**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☒ No ☐
Comment: The proposed requirements P2, P3 and P4 significantly increase system performance. I agree with the requirements but I do not think it is appropropriate to layer extreme load, extreme transfers and other sensitivities on top of these. The analsysis of any Senistivities should be under the umbrella of Extreme Events or limited to meeting the P1 requirements.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒
Comment: Stability studies are a labor intensive task. Off-peak studies (with max plant gen) is severe enough.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☐
Comment: I agree with the approach.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes

all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒

Comment: DSM and generation improvements should be excluded. What is a "generation improvement"? New technologies could apply to anything, does the SDT mean "new Transmission technologies"?

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒

Comment: Re-testing is part of the normal study process of developing the Corrective Action Plan (CAP). Most CAP should be developed in the Long-Term horizon. The next annual study and all subsequent studies provide sufficient review without developing another set of cases and additional testing in the initial assessment.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒

Comment: MISO has spent years on trying to make a distinction. If this remains, then "Committed Project" must be defined.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒

Comment: Our planning process includes documentation of the need, acceleration, delay, or elimination of all projects. As worded, I do not need to document the delay of a Committed project.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-

0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Outage of two 345 kV circuits can create local area issues that result in loss of load but do not affect the integrity of the BES.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Outage of two 345 kV circuit and a transformer can create local area issues that result in loss of load but do not affect the integrity of the BES.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of	☐Agree. ☒Do not agree.	Outage of two 345 kV transformers can create local area issues that result in loss of load but do not affect the integrity of the BES.

another transformer		

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: EHV station configurations are either ring-bus or breaker and one-half. Breaker failure protection isolates two EHV Facilites which may cause local area issues without affecting the BES.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: This event needs to be reworded. Does the stuck non-bus tie breaker condition only apply to the bus fault or to all faults? Does (above 300 kV) only apply to the stuck non-bus tie breaker or is this limited to faults on facilities above 300 kV?

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed	☒Agree. ☐Do not agree.	

[1] System adjustment can be manual or automatic

by loss of a transformer		

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment: No opinion, we do not operate DC

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment: Yes but the distinction is not clear in the defintions. A Plant Stability Study would typically be done as part of the Generatior Interconnection Request and have all units in the area at maximum output. Is the System Stability Study done on the Base Case or is generation maximized within some area(s)?

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: I agree with the SDTs conclusion.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: I agree that this is an issue but I do not have sufficient data to accurately simulate the condition. This is also complicated by dynamic behavior of distribution capacitors which are not modeled.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: single - none

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☒

Comment: I do not agree that the system has to be returned to a "normal state" after a single contingency. The system can continue to be operated in the "emergency state" as long as the next contingency does not cause flows above emergency ratings.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐

Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:
R1.4 "including protective relays with consideration given to spare equipment strategy" I do not understand the intent of this phrase or what it adds to the requirement.

R2.6.1 "and market structure changes" What is this, does it require a definition?

R2.7.1.1 What is the project initiation date; the date approval is sought, received, materials are ordered, construction begins? Many projects are upgrades or replacements that this will be meaningless. Don't you really only want multiyear projects?

R2.7.2 The initial study process will incorporate testing. This will require the creation of additional cases and additonal testing prior to the Planning Assessment submittal. Most projects should be identified during the Long Range time frame. Inclusion of the project in the next years base cases and subsequent testing should be adequate.

R2.7.3 Define a "Committed Project". MISO has spent years on this.

R2.7.4 Changes in timing of all projects should be documented in the Planning Assessment. Why would you document Committed Projects that are removed but not any delays or accelerations?

R3 Sensitivity studies (if retained) should have less stringent performance requirements than the other cases required by R2.1.

R3.3.2.1 Unless this is limited to above 300 kV, many hours will be spent for naught. The lower voltage systems often have tapped loads that will trip with the line. The time required to restore will vary on the fault location, and time for switching, sometimes remote and sometimes manual. I do not see the need for or the benefit of this requirement. Please explain.

P3 Event is poorly worded, see response to Q25.

P6.1 above 300 kV, below 300 kV or all? The tables need to be reviewed to make sure that the voltage applicability is clearly stated.

P9.6 Why is this a requirement? It should be much less severe than any of the prior requirements.

Extreme Event 9 (3ph fault with loss of all generating units at a station) is in conflict with Q33 which says it was not included). Am I missing something?

Other, it appears that we are not required to study the outage of a transmission line or transformer followed by the outage of a generator. Was this overlooked, or did I miss it? Would system adjustment be allowed?

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Larry Rodriguez	
Organization:	Entegra Power Group	
Telephone:	813 301-4952	
E-mail:	lrodriguez@entegrapower.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☒ **SERC** ☐ **SPP** ☒ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☒	5 — Electric Generators
	☒	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: Further examination is needed to determine how to correctly treat loads served downstream from the faulted element, but not directly connected.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: The statement would be clearer if "low" were changed to "lower".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	

Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Should also include validation of reactive power supplies.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.

- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☐
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☐
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment: Planners should use appropriate sensitivity cases.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in

conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☐
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL

standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the

[1] System adjustment can be manual or automatic

steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected

Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment: As long as the system would be within normal ratings after runback.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☐ No ☐
Comment:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)			
Name:	Charles W. Long or Doug Powell		
Organization:	Entergy Services, Inc.		
Telephone:	601-969-2324 or 504-576-3584		
E-mail:	clong1@entergy.com or rpowel1@entergy.com		

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: Delete "mis-operation". For purposes of planning, all consequential load loss should reflect intended fault clearing actions and not unintended fault clearing actions (i.e., mis-operations). Include load loss due to UVLS & SPS in consequential load loss category.** **Consider using the terms in the existing standard; "Planned Load Loss" and "Unplanned Load Loss" in lieu of Consequential and Non-consequential as they may be easier to define with each Transmission Owner/Planning Authority responsible for defining the terms considering the impact on the Bulk Electric System.** **If the terms remain as proposed, the definition needs further clarification for consequential and non-consequential loads. For example, loads entirely dependent on the faulted element but not directly connected should also be defined to be consequential loads.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Revise to, "Events which are beyond the normal scope of Planning Events and have a lower probability of occurrence."**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.

Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: We recommend to treat load losses due to UVLS & SPS as examples of consequential load loss (refer to question 2).**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Remove "and other factors, such as asset conditions and age" from definition. The terms "age" and "condition" are subjective and the age of equipment, if it is well maintained, has little impact on reliability.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Delete the term "the effect on the System of." The reference to "System" causes confusion with the term "System Stability Study."** **Section R4.6 should identify the Generator Owner as the applicable party for doing the Plant Stability Studies.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: The last sentence in the above definition was not included in the definition listed in the draft standard. Consider deleting the last**	

sentence or providing additional examples.

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The appropriate studies that should be done by each applicable entity is highly dependent on the transmission system being studied. Being too prescriptive may cause irrelevant studies to be completed while diverting resources and attention from sensitivity studes that the entity most familiar with the transmission system believes could result in more meaningful analysis. The Committee should not lose sight of the importance of good engineering judgment exercised by those most familiar with the characteristics of the particular system. While appropriate sensitivity analyses are beneficial in evaluating system performance, it should be clearly stated that projects and/or mitigation plans are left to the discretion of the Transmission Planners.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: Should be left to Transmission Planners discretion and good engineering judgement. (see response to Q12)

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒
Comment: The new requirements for stability studies, including but not limited to the sensitivity studies, will result in a tremendous increase in workload. Because stability studies are so much more time intensive that steady state analysis and because they require personnel with a highly specialized skill set, the number of stability studies required should be increaed only as determined necesssary to evaluate worst-case contingencies. It would seem that the sensitivity analyses as well as many of the multiple contingency analyses could be done for steady state and only worst cases analyzed again by dynamic studies.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: DSM should be considered, but it should be done prudently and in accordance with the contracts that govern the specific DSM program and only in cases where the Transmission Owner has direct load control. Transmission Owners should be allowed to include UVLS and SPS systems as a part of their Corrective Action Plans.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: Study area should be determined on a case by case basis by the Transmission Planner. SEAMS agreements and other regional planning coordination activities should provide for adequate cooperation.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: Committed projects should be tested for effectiveness, however, the effectiveness of Proposed projects, as they are subject to change, should not require the same level of documentation as committed projects.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus	☒Agree.	Table 1 does not specify "SLG"

section (SLG for stability) above 300 kV	☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	N-1-1 requires an increase in investment that will place an undue cost burden on all customers for low probability events. See comments to Q43.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	N-1-1 requires an increase in investment that will place an undue cost burden on all customers for low probability events. See comments to Q43.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	N-1-1 requires an increase in investment that will place an undue cost burden on all customers for low probability events. See comments to Q43.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: N-1-1 requires an increase in investment that will place an undue cost burden on all customers for low probability events.
See comments to Q43.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: N-1-1 requires an increase in investment that will place an undue cost burden on all customers for low probability events.
See comments to Q43..

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	This would require an increase in investment that will place an undue cost burden on all customers for low probability events. It does not appear that there has been any meaningful balancing of the potential benefits against the significant increase in cost that will be required. See comments to Q43.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	This would require an increase in investment that will place an undue cost burden on all customers for low probability events. It does not appear that there has been any meaningful balancing of the potential benefits agains the significant increase in cost that will be required. See comments to Q43.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	This would require an increase in investment that will place an undue cost burden on all customers for low probability events. It does not appear that there has been any meaningful balancing of the potential benefits against the significant increase in cost that will be required. See comments to Q43.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	This would require an increase in investment that will place an undue cost burden on all customers for low probability events. It does not appear that there has been any meaningful blancing of the potential benefits against the significant increase in cost that will be required See comments to Q43.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

[1] System adjustment can be manual or automatic

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☒
Comment: Why are only DC lines exempt for this requirement? Consider exemptions for AC transmission elements as well.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment: This approach clarifies the types of stability studies/simulations to be performed. The performance criteria/guidelines are more explicit under the proposed Standard.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment: See response to Q9

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: This question conflicts with Table 2 item 9. However, we feel it is not necessary to simulate loss of all units at a station. The Transmission Planner or Planning Authority should have the discretion to consider the appropriate number of units to be tripped based on station design, relay design, etc.

Since there is no specific question related to R3.4 that requires an evaluation be conducted of implementing a change designed to reduce or mitigate the likelihood of such consequences. More specific direction should be provided in this regard.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: In general this is a good practice. Dynamic studies of seasonal load conditions should include the effects of induction motors, and particularly in areas where

traditional load models have indicated a problem. Unfortunately, there is a lack of data to support the amount and characteristics of the detailed induction load models in many areas. In addition to the consideration of the dynamic effects of induction motor loads, the effects of static capacitor banks installed at distribution voltage levels would need to be considered as well. Prior to making this a requirement in the reliability standards, the industry needs guidance as to how this data should be developed and maintained for models in future years. This should be a business practice and thus removed from the standard. While we agree that each entity should appropriately model their loads, it would seem appropriate for the MMWG to address the issues of induction motor load modeling.

Note that meeting such a requirement would necessitate a significant increase in the dynamic data needed to represent the system. Maintenance of such load model data would require significant resources. Load characteristics valid for a near term model might not be valid for future years.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: This question is not clear and more explanation should be provided, such as, whether the adjustments are pre or post contingency, whether the contingency involves faults etc. Does this question pertain to plant or system stability?

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☒
Comment: The question is not clear. Generation runback schemes are acceptable as long as emergency ratings are not violated. Runbacks should not be used to restore an element to within emergency ratings.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: RAS or SPS may be allowed for single contingencies when they aid in meeting System Performance requirements. RAS and SPS should not be used to restore an element to within emergency ratings.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: RAS or SPS may be allowed for single contingencies when they aid in meeting System Performance requirements. RAS and SPS should not be used to restore an element to within emergency ratings.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: Following a contingency, power flows on lines should be within their emergency ratings, voltages should be at adequate levels and system should be stable.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:

Significant Increase in Study Activity Workload on Transmission Planners

The increase in both steady state and dynamic studies required to ensure compliance with the proposed standards will result in increased costs and staff additions. The more specific format and additional requirements of the "Corrective Action Plan" require the TP to provide a significant amount of documentation for each deficiency identified by the studies. Also, R3.2 requires that the studies simulate the protection scheme for all events. The current software tools cannot automate these studies for bus faults and breaker failure events, requiring each scenario to be studied manually. Additionally, experienced staff capable of performing analyses as described in the proposed standard have become increasingly difficult to find and retain and the talent pool of people with these skills has recently become depleted to alarming levels.

Implementation Plan

Given the intent of the proposed standard to encourage large scale investment in the EHV system, full implementation will take years, perhaps decades. Acquirement of right-of-way for new EHV lines has become increasingly difficult in recent years and increasingly expensive due to the environmental and social issues associated with new Transmission. Legal, regulatory, and other difficult issues often take several years to navigate, even for 115kV lines. The Implementation Plan timeframe, if set too short, would be unduly burdensome on Transmission Owners, extraordinarily expensive, and possibly unachievable. The proposed implementation plan should include provisions for those cases where viable solutions simply can not be implemented in time due to circumstances beyond the control of Transmission owners. We recommend a minimum of 15 years for the transition.

Design and Construction Constraints

Even if right-of-way and other legal and regulatory hurdles are cleared, and the capital funding for such a tremendous level of investment was not an issue, the other resources required to actually construct the projects are equally difficult and costly to secure. Raw material prices on commodities like copper and steel have skyrocketed in recent years. Additionally, the skilled labor and Engineering resources are constrained with labor rates almost keeping up with other resource costs. Overall project costs have more than doubled over the last 7-10 years. Recent press releases concerning new generation being planned and then scrapped due to the rapid escalation of project costs are public evidence of this. The inflationary mark-up is impossible to estimate but much less will be built with the same capital investment than is currently envisioned due to the competition for both human and material resources.

Cost-Benefit Analysis

It will be extremely expensive, requiring unprecedented levels of capital investment in Transmission facilities, to become compliant with a proposed standard without any evidence that such increased requirements are justified. Before the standard comes to official vote, it would be prudent for a cost-benefit analysis to be performed to determine if the reliability improvements justify the huge expenditures certain under the proposed standard. A clear understanding of the reliability benefits and economic costs to customers is critical prior to final action on the proposed standard. While tightening standards will result in a more secure system, overbuilding the system at a significant cost to withstand more severe but less likely contingencies may not be in the public interest. Additionally, it is unclear whether the propose standard is in conflict with section 215 of the Energy Policy Act of 2005.

System Adjustment Clarification

The term "System Adjustment" as outlined in the tables should be better defined. The use of generation for redispatch may have nuances which preclude or otherwise limit their use for studies. Perhaps some clearer guidelines on what is allowed such as committing units, de-committing units, firm and non-firm use, etc. would facilitate transparency and coordination between Transmission Planners.

Transmission Service Evaluation

Another concern is that the proposed standard appears to be inconsistent with the current requirements for evaluating firm transmission service, generally based on an N-1 standard. To the extent this standard is adopted as proposed, the new standard would also need to be incorporated into the standards against which new transmission service is granted.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	H. Steven Myers	
Organization:	ERCOT ISO	
Telephone:	512-248-3077	
E-mail:	smyers@ercot.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☒ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☒	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment: It is a fair description for an initial base case.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment: Agree with the definition**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Add specificity in this definition. Suggest the following wording: Outage of two or more elements from service with lower probability of occurrence than Planning Events**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment: Agree with the definition**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: Agree with the definition**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: Add Remedial Action Schemes (RAS) after "Systems" Amend sentence beginning "For example, Load loss that "directly"**	

occurs…………	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☐Do not agree.
Q7. **Comment: Agree with the definition**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Needs clarity. Suggest the following wording: Outage of power system elements such as shown in Tables 1 and 2 that need to be considered and simulated to assess Transmission System Performance**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Definition is not clear. Suggest the following wording: Study of an individual generating plant's capability to remain in synchronism and exhibit damping of the generating units' power oscillations for various contingencies in the vicinity of the plant**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: This definition is for a stable system. Study is performed to determine whether system is stable or not. Suggest the following wording: Study of the system or portions of the system to assess the system's performance in terms of angular stability, power oscillations and voltage limits during dynamic simulation**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: Suggest a shorter definition: Planning window beginning next calendar year**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The TP or PA is the best to determine the number and type of sensitivities that are more applicable to their system.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: Let the TP or PA decide the type of stressing needed for a particular case

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒

Comment: Although we concur with the sensitivity analysis,the TP should determine what sensitivities are more appropriate for their system. Sensitivities should not be scripted in the Standard.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: Agree. The Standard should state that sensitivity studies are not required but the TP or PA could use sensitivities if desired.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: We agree that the system should be retested with the corrective measures to ensure that the defficiency has been cured and that there are no inadvertant negative impacts. Regarding Study Area, it is not a defined term, and it could vary depending on the size of the project or nature of the disturbance being evaluated.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: The definition of "committed" projects varies from TP to TP. Also projects that are proposed today become committed in the planning horizon. Similarly, committed projects drop out due to variety of reasons. In terms of system studies, both committed and proposed projects are modeled and evaluated in the same system. How do we distinguish between the two?

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: We agree that committed projects should not be removed from the revised plan. These are supposed to be included in the planning studies which determine the system performance in the first place.

The definition of "committed" projects varies from TP to TP so this would require a standard definition.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	This event falls under Category C for which controlled loss of load is allowed. Clear net benefits should be demonstrated to justify adapting to a new stringent criteria.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	We will comment on this at a later date
Q23. P5-3: For facilities	☐Agree.	We will comment on this at a later date

above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: Same response as for Q21, and
What is the definition of non-bus tie breaker? Doesn't it just refer to line, transformer, and generation breakers?

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: Do not agree for loss of a bus, or loss of a stuck non-bus tie breaker for the reasons as in the response to Q21.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	Non consequential loss of load should not be permitted for this type of event. Loss of a generator has higher probability and longer duration than many other contingencies. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Q27. P4-2: Loss of a	☒Agree.	Agree that non consequential loss of

[1] System adjustment can be manual or automatic

generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Do not agree.	load should not be permitted due to higher probability of generator outage.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	Same reason as in Q26.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☐Do not agree.	Same reason as in Q26.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: In addition, the interruptible and other negotiated transactions should also be allowed.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment: Agree that the two analysis should be treated separately.
It is not clearly defined what is steady state and what is stability. For example are Voltage Stability (PV analysis) studies steady state or stability? Also what are the differences between System Stability and Plant Stability? Are stability studies only required for the near term planning horizon?.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment: Agree with this additional analysis

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment: It will be consistent with the performance requirements under Steady State conditions. Also, loss of entire generating station is possible for a variety of reasons such as, loss of all lines emanating from the station, loss of the gas pipeline feeding the plant, etc.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: The requirement to include motor load should be extended to other load levels as appropriate.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Manual such as tripping the generators, automatic such as AVR, excitation systems, stabilizer, and governor adjustments.
From a Planning perspective, you would not want to allow for manual tripping in the time frame of a stability study.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment: Agree

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: 1. Run back of generation should not result in tripping of firm load, 2. Power flow should be within the applicable ratings, 3. Frequency should be within the allowable limits

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: Agree

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: RAS or SPS should generally be regarded as a stop gap measure before transmission expansion or reinforcement becomes available. It should not be used as a substitute for transmission facilities.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: 1. RAS or SPS must be simple and manageable. 2. Number of contingencies triggering a RAS or SPS should be very limited (4 allowed by CAISO). 3. RAS or SPS should generally monitor only local facilities that are either directly connected to the plant or one bus away.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: ISO relies upon tripping of generators to meet single contingency performance requirements. ISO also relies upon planned and controlled load shedding for the proposed Planning Events P4 and P5.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment: Not aware of any

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☐ No ☒

Comment:

R1.1.1 - Are percentage of load that is industrial, commercial, and residential needed?

R1.2 - The wording is confusing. If the power factor is based on historical measured values, does it have to be during contingency (stressed)?

R1.5 - "Planned Facilities defined in accordance with the documented criteria of the Planning Coordinator" - what is meant by this?

R2.1.1, R2.1.2, R2.1.3.1 - are all studies to be run using all the contingencies defined in Table 1 - Steady State Performance?

R2.6.1, R2.6.2, R2.6.3 - past studies will never be able to be used if the addition of a transmission line makes them invalid!

R3.2.1 - What is meant by "minimum steady state voltage limitations of all generators"?

R3.2.2 - Relay "loadability"?? What is meant by this? Sounds unreasonable for steady state studies as facility rating should reflect limitations of relay equipments such as CT"s.

General comment: If this proposed standard is approved, since it contains requirements that are more restrictive than current standards, there will need to be a transition period to allow transmission to be built to allow systems to meet the new requirements.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Eric Mortenson	
Organization:	Exelon	
Telephone:	(630) 576-6898	
E-mail:	eric.mortenson@exeloncorp.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☐Agree. ☒Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment: 'Other factors' such as condition and age should not be required, but may be utilized if these factors are an integral component of the study.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Wording should be changed to allow for engineering judgment to determine which contingencies are applied. There may be instances where contingencies outside of the immediate vicinity of the plant may be significant to its stability. Suggest replacing the word 'System' with 'Transmission System'.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment: Suggest replacing 'System' with 'Transmission System'.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: The required changes should not be specified because they may not impact a particular transmission system based upon its geographic location within the interconnection. Required changes should be determined by the entity performing the study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: DSM should be directly controllable with accurate information as the the magnitude and location. System stability should not be dependent on the operation of DSM.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: The study area should be at least the size of the original study area. Some engineering judgment is required to determine the subset of studies. Next year's study would include the full set of screenings for the future additions.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to “raise the bar.” Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☒Do not agree.	We do not agree with disallowing non-consequential load loss for these scenarios for the peak load conditions. These are very low probability contingencies, and some non-consequential load loss should be allowed at peak load. We would agree that it would be reasonable to dis-allow non-consequential load loss for these contingencies at a lower load level, such as 75% of peak load.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☒Do not agree.	We do not agree with disallowing non-consequential load loss for these scenarios for the peak load conditions. These are very low probability contingencies, and some non-consequential load loss should be allowed at peak load. We would agree that it would be reasonable to dis-allow non-consequential load loss for these contingencies at a lower load level, such as 75% of peak load.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☒Do not agree.	We do not agree with disallowing non-consequential load loss for these scenarios for the peak load conditions. These are very low probability contingencies, and some non-consequential load loss should be allowed at peak load. We would agree that it would be reasonable to dis-allow non-consequential load loss for these contingencies at a lower load level, such as 75% of peak load.
Q23. P5-3: For facilities	☒Agree.	We do not agree with disallowing non-

above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Do not agree.	consequential load loss for these scenarios for the peak load conditions. These are very low probability contingencies, and some non-consequential load loss should be allowed at peak load. We would agree that it would be reasonable to dis-allow non-consequential load loss for these contingencies at a lower load level, such as 75% of peak load.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: P6 allows for non-consequential load loss for a bus tie breaker, which has the same probability of failure as a non-bus tie breaker.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☒
Comment: We do not agree with disallowing non-consequential load loss for these scenarios for the peak load conditions. These are very low probability contingencies, and some non-consequential load loss should be allowed at peak load. We would agree that it would be reasonable to dis-allow non-consequential load loss for these contingencies at a lower load level, such as 75% of peak load.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a	☒Agree.	

[1] System adjustment can be manual or automatic

System adjustment followed by the loss of a monopolar DC line	☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☒

Comment: This is more pertinent to longer term voltage stability, so the load model should be developed and available for these types of studies.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Generator MW and Mvar output adjustments should be allowed, both manual and automatic.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: An automated run-back scheme should be allowed but not required for these scenarios - an operator should be able to manually adjust unit output.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Run-back schemes should be allowed for certain single contingencies that can result in unit outlet constraints. Not all emergency ratings are thermal - some are relay or stability limits. In these instances, generator run-back should not be allowed.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: There should be more specific requirements for the long-range studies. The P requirements should be run on the long range case but corrective action plans need only be proposed and not committed.

R3.3.2.1 appears to require consequential load loss identification including peak demand and duration. however there is no requirement addressing the use of this information. Why is this required?

R3.3.3 should be clarified. It is our interpretation that not each of the P contingencies be studied if sufficient rationale is provided to determine the most critical. It would seem that each of the planning category events would need to be addressed.

What is the expectation regarding sensitivity analysis in R2.1.3 and R.2.4.3 if there are no performance requirements defined?

It should be clear in the performance tables that the 'event column' contingencies are logically 'or' events.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**	
Name:	Doug Hohlbaugh
Organization:	FirstEnergy Corporation
Telephone:	330-384-4698
E-mail:	hohlbaughdg@firstenergycorp.com

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: **FirstEnergy Corp**

Lead Contact: **Doug Hohlbaugh**

Contact Organization:

Contact Segment: **1-Transmission Owner**

Contact Telephone: **330-384-4698**

Contact E-mail: **hohlbaughdg@firstenergycorp.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
John Stephens	FE	**RFC**	1
Dave Folk	FE	RFC	1
Sam Ciccone	FE	RFC	1

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: We suggest that the team remove "or misoperation" from the definition. This could suggest that an overtrip of protection equipment could result in consequential load loss.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment: The definition is OK, but we question its use in the standard. Many of the items listed as extreme events are not considered events. For example, high river temperature is not really an event, it is a condition. The resulting event might be the shut-down of multiple generators.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding,	☐Agree. ☒Do not agree.

or Special Protection Systems.	
Q6. **Comment: We suggest eliminating the reference to Special Protection Systems (SPS). Some SPSs could result in tripping of load in association with a fault. By specifically listing SPSs here, it could imply that if that situation occurs, it would not be considered consequential load drop.**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: We suggest replacing "performance studies" with "past or present studies or information".**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: We ask that the SDT reword the definition to include reference to the planning events in Table 1 and 2 of this standard. This definition should be specific to this standard and not be included in the NERC glossary.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: We believe that this definition is not needed. The Plant Stability Study is similar to the System Stability Study.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: Although we agree with the concept, the definition is confusing. We suggest simplifying the definition to "The first 12 month period that begins one year and one day from the completion of the study."**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii “Sensitivity studies and critical system conditions” FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: We suggest that the SDT reword the standard to allow the Transmission Owner additional latitude as to which stress conditions to study. We suggest modifying R2.4.3 to indicate sensitivities "such as those listed below" be studied. That way the standard would be providing examples but would not dictate specific sensitivity studies that should be performed.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment: Although we concur with the use of sensitivity analysis in dynamic studies, the standard should not dictate the specific sensitivities studies to be performed.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: Yes, we concur with this approach and sensitivity analysis should not be required.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒
Comment: We do not feel that the standard should specify, limit, or suggest methods for mitigating system performance deficiencies. We suggest rewording R2.7.1 by ending the first sentence after the words "System performance". The items currently described could be moved to a reference document which could include DSM and other mitigation methods.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: Although we agree with the concept of retesting, the standard should reference that a re-study is only required in the vicinity or portion of the system affected by new facility additions. Determination of the study area should be left to the Transmission Planner's judgement.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: Unless there is an industry agreed upon distinction and definition between "committed" and "proposed" projects, we do not agree that they should be introduced in this standard.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: Unless there is an industry agreed upon distinction and definition between "committed" and "proposed" projects, we do not agree that they should be introduced in this standard.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System	☐Agree. ☒Do not agree.	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused

adjustment followed by loss of a transformer with low side voltage rating above 300 kV		soley by the first contingency.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: The tables' use of internal faults and stuck breaker faults is confusing since they have the same result.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: The wording of P3-1 is unclear. We suggest rewording to say "Fault on a generator, line, transformer, or bus and a stuck breaker when the fault is being cleared". We agree with the concept of not dropping load for an EHV stuck breaker with the exception of the bus fault item. We do not believe that it is very realistic to postulate a bus fault along with a stuck breaker and believe that it is a very low probability event.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for

[1] System adjustment can be manual or automatic

		problems caused soley by the first contingency.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☒
Comment: While we agree that steady-state and stability are different situations, in general we believe that the tables are confusing, overly worded, and should be combined. The initiating events are the same regardless of steady-state or stability so there should be no reason not to combine the tables as was done in the previous standards.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒

Comment: We do not see the difference between plant stability and system stability. Both are based on anuglar stability of machines connected to the system and therefore, they should be treated the same.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment: We do not believe that this condition should be required to be tested using stability analysis of extreme events. This is due to the fact that these events should be required to be studied using steady state analysis, and stability analysis results would not add value.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐

Comment: We agree with this concept but believe that enforcing it would be very difficult. There are no standards on modeling induction motor load, be it type of models, percentage of load that is motor load, or percentage of large vs small motors.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: As long as thermal, voltage, and stability requirements are met, either automatic or manual runback of the unit should be allowed. Tripping of the unit should be allowed also if the particular unit(s) can be restarted within some relatively short time - say one hour. With this requirement, it appears that only CTs and hydro units would be allowed to be tripped.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency

outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment: As long as thermal, voltage, and stability requirements are met, either automatic or manual runback of the unit should be allowed. Tripping of the unit should be allowed also if the particular unit(s) can be restarted within some relatively short time - say one hour. With this requirement, it appears that only CTs and hydro units would be allowed to be tripped.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Yes, only if the Transmission Owner has documented short term ratings that would not be exceeded during the runback.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: As long as thermal, voltage, and stability requirements are met, RAS or SPS should be allowed provided it does not shed load for a single contingency event.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: As long as thermal, voltage, and stability requirements are met, RAS or SPS should be allowed provided it does not shed load for a single contingency event.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: As long as thermal, voltage, and stability requirements are met, RAS or SPS should be allowed provided it does not shed load for a single contingency event, and only if the Transmission Owner has documented short term ratings that would not be exceeded during the runback.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:
- R1. Load flow model submittal is redundant with various MOD standards and should not be required by this standard. To the extent any new requirements are introduced, we suggest that existing MOD standards be revised or new MOD standards be created as needed.

- R2 Organization of this requirement could be improved by grouping by Near Term and Long Term and then by steady state, short circuit, and stability requirements.

- R2.1 Too many annual studies are being required by this standard for the Near Term. We suggest limiting the current study year requirement be limited to one Near Term study. As written, it appears that this requirement forces a study for each of the 5 years, however the requirement should to be able to assess the entire 5 year period but not study each year.

- R2.1.1: As written, 2 studies are needed to meet this Near Term assessment requirement. It should be left up to the TO to determine the appropriate year in the short and long term periods. It's particularly odd given the fact that the TO could select year six for the Long Term study which would end up giving him back to back year 5 and 6 studies. The requirement should be to study one year in the 1 to 5 and one year in the 6 to 10 year periods.

- R2.2: This wording is very confusing. We are assuming that it means that you must continuously have to have a study that is less than one year old for the year 6 to 10 period. If so, wording needs to be clarified.

- R2.4.1: The idea of modeling induction motor loads is good in concept, be we question the practicality for an auditor to enforce. To date, a definitive way to model induction motor load does not exist. For example, what is the right mix for percent of load to be motor load or percent of large vs small induction motors.

- R2.6.1: Unless "material change" is specifically defined, the requirement is ambiquous and difficult to enforce consistently. What constitutes a "topology" change?

- R2.6.2: Same comment as R2.6.1 above, material change needs to be defined.

- R2.6.3. Same comment as R2.6.1 above, material change needs to be defined.

- R.2.7.1.1: We don’t think it is reasonable nor necessary for the TO to provide an initiation date. No one should care when it was initiated as long as it is in service by the time it is needed.

- R2.7.1.2. Requiring an in-service year for the long-term may not be feasible for the initial study assessment. Based on the number of issues that could occur in the long-term horizon it may take a TP another 6 months to a year of more detailed area studies study to find the optimal solution(s) to resolve multiple system deficiences. In the long-term, only a list of SOLs problems along with year problem is initially anticipated should be required.

- R3.2.1: We suggest the following rewording "R3.2.1. Studies shall include the minimum steady state voltage limitations for all generators, and generators shall be simulated to trip for voltage below the minimum steady state limitation."

- R3.2.2: This is unnecessary in this standard. This is already addressed in the FAC standards dealing with equipment rating. Additionally, the proposed PRC-023 relay loadability standard addresses this concern. Alternatively, reword the requirement to say "if a relay is expected to trip because of an overload then the resulting facility shall be simulated in addition to the initiating event".

- R3.3.3. How do you know which events beyond single contingencies result in producing "more severe" impacts without running all? Either you test or you don't. We suggest some type of cyclical expectation for testing each of the less probable Planning Events, i.e. every three years each must be covered etc.the most critical

- R3.4 Same comment as R3.3.3, you need to test each to understand which produces the most severe impact. We suggest some type of cyclical expectation for testing each of the Extreme Events. The frequency of testing should be less often that the items covered in R3.3.3. It appears the only expectation is to consider some type of change to reduce or mitigate potential Cascade for Extreme Events. It should be clearly written that there in no mandatory expectation to remove the Cascade risk that may be associated with an Extreme Event.

- R4.5.1. Same comment as R3.3.3 (Steady-State) applies for this Stability requirement.

- R4.5.2. Same comment as R3.4 (Steady-State) applies for this Stability requirement.

- R4.6.1. We agree with the requirement but the SDT should assure consistency with data submittal requirements in the MOD standards.

PERFORMANCE TABLES - General
1. In general, we feel the tables are overly complicated and difficult to follow. We suggest the SDT give consideration to merging the proposed tables back together to a single performance table. We also question why the team chose to leave the NERC A, B, C, D concept. The concept of Planning Events could reflect that NERC A, B & C categories must be met for Planning Events and that Category D are Extreme Events. Drastic deviation from the historical NERC performance classifications will require significant re-write of existing TP planning criteria documentation.

2. 300kV Level - It is confusing how the 300kV level requirements are placed within the tables. We suggest separate columns for performance requirements for 300kV and higher and below 300kV. This way, the same Planning Event could easily be reference on the same line and the expectations for each system level could be more readily determined.

TABLE 1 - Steady-State Performance Table

1. We suggest that the "Initial Condition" column that is included in Table 2 - Stability Performance Table - also be added to Table 1. This would allow each to have the same look and feel, and would cut down on the lengthy wording such as: "Loss of a generator followed by System adjustment followed by loss of a generator"

2. Bullet 1 - "Equipment Ratings should not be exceeded." It is not clear which equipment rating would be the applicable rating.

3. Bullet 3 - "Voltage instability, cascading outages and uncontrolled islanding shall not occur". These terms require a definition to ensure consistent interpretation and application from an auditor.

4. It is not clear why stuck breaker items are distinguished from an internal breaker fault. Each will create the same resulting system condition.

5. Why are non-bus tie breakers treated separate from other breakers?

6: P2: Why is a stuck breaker listed as a single contingency?

7. P8: What about a transformer followed by a line outage? Why not just simply list the components and say any combination of the two.

8. P9: "Loss of a transformer followed by a System adjustment with a spare transformer available followed by the loss of another transformer." It is not clear why this is needed? Wouldn't the spare be a possible mitigation of the initial contingency?

9. Extreme Event Descriptions:

A) For item 1, it’s understood that for the N-2 items listed, the "extreme" aspect is that the second event occurs without system adjustment. However, we question whether a two generators simultaneously out should be considered an extreme condition.

B) We agree with the items listed in item 2 as they line-up well with the prior category D events from the existing TPL standards performance table.

C) Many of the classifications listed in item 3 are subjective and can not be tested. We propose that these items should not be requirements.

TABLE 2 - Stability Performance Table

1. With regard to Table 2, much of the proposed testing required for stability are not necessary from a reliability standpoint. Some test items are included that are not, at least in the eastern interconnection, going to impact stability any worse than the relatively simpler requirements of the present standards. By testing single phase local faults in conjunction with a stuck breaker and remote faults with back up clearing for each line emanating from a power plant, you'll cover 99% of your stability issues. Also, this table does not adress relay scheme failures (back up clearing) that were covered in the present standard and which can have a significant impact on the stability of a unit/system.

2. Under the "Event Column", it is inconvenient to need to look back and forth on the table to reference other events, the items should be written in full text. For example, under P4 it is indicated that the "Initial Condition" is a single generator out and the "Event Column" indicates apply "P1.2 Contingency, P1.3 Contingency, etc." These items should be written out so that the user of the Table does not need to flip back and forth to see what the referenced contingencies entail.

3. Regarding P1, why require dynamic analysis for an unexpected loss of the listed equipment without a fault? The fault iniated outage will always be worse.

4. As stated above for Table 1, It is not clear why stuck breaker items are distinguished from an internal breaker fault. Each will create the same resulting system condition.

5.: P5, P8, P9: The analysis suggested to run these multiple contingencies in dynamics would be extremely time consuming and produce little value. We suggest that the steady-state anlysis be used to screen those contingencies which show the potential to cause system cascade and then run dynamic analysis on those items.

6. As stated for Table 1 above, "Loss of a transformer followed by a System adjustment with a spare transformer available followed by the loss of another transformer." It is not clear why this is needed? Wouldn't the spare be a possible mitigation of the initial contingency?

7. In the Notes section shown under Table 2, for item "ii", we are not sure this could be accomplished as our relay models are not reflected in our data set used for dynamics simulation analysis. Two separate and unique software tools house the data and we believe this to be common among most companies.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Hector Sanchez	
Organization:	Florida Power and Light	
Telephone:	305 442 5062	
E-mail:	Hector_Sanchez@fpl.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☒ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*
Marty Mennes	Florida Power & Light Company	**FRCC**	Transmission
W. R. Schoneck	Florida Power & Light Company	FRCC	LSE
R. A. Birch	Florida Power & Light Company	FRCC	GO
A. L. Barredo	Florida Power & Light Company	FRCC	LSE
C. Candelaria	Florida Power & Light Company	FRCC	LSE
J. W. Shaffer	Florida Power & Light Company	FRCC	LSE

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: "Computer" is not appropriate. Replace with "Data model" or "Database model". The last sentence is not clear as to what type of ratings (i.e., normal, short-term emergency, long-term emergency, etc.). Suggest removing sentence completely or rewording as follows: "... in accordance with the documented methodologies required by FAC-008 for each Transmission Owner and Generator Owner."**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: Need to clarify what constitues an element (e.g., breaker-to-breaker, line segment to line segment, transformer or capacitor bank)**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Suggest reword as follows: "Events which are more severe and have a lower probability of occurrence than planning events."**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	

Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: Reword as follows: "Firm load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems, excluding curtailments, DSM, and voltage reduction."**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Last part of the last sentence should be removed "… and other factors, such as asset conditions and age" does not make sense for planning studies. Equipment condition and age are maintenance issues not transmission planning issues.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: There should be no distinction between Plant Stability and System Stability. All stability studies must meet the Performance Requirements for Planning Events in Table 2 - Stability Performance. If there were different Performance Requirements then the distinction would be warranted.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: Dynamic voltage ratings do not add value and are only an approximation for modeling limitations. The definition should not address performance and should only seek to define the term. Reword as follows: "Study of the System or portions of the System to assess angular Stability and inter-area power oscillations."**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the	☐Agree. ☒Do not

Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	agree.
Q11. **Comment: The last sentence of this definition is not included in the Standard. Reword as follows: "The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner performs their annual studies and submits the results to the RRO."**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: Not all Regions' sensitivity concerns are the same.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: The Transmission Planner needs the flexibility to define what are considered "reasonably stressed" cases for their respective systems. This would not a be a proper application of a one size fits all definition.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒

Comment: The standards require near term base case cases to be studied for a broad range of planning and extreme events. The sensitivity analysis requirements contained R.2.4.3. will essentially require every dynamic simulation to be run at least twice regardless of whether or not there is any engineering insight to be gained. While improved understanding may result from sensitivity analysis of certain key event scenarios, the overall benefits of the sensitivity study requirements contained in section R.2.4.3 do not justify the huge increase in engineering effort to conduct and document these simulations.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: There should be no sensitivity studies/analyses for the Long-Term Transmission System Planning Horizon.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: If DSM is included as part of an integrated Corrective Action plan, then the impact of DSM should be included by specifying the location and expected quantity of DSM that will mitigate a system deficiency. The use of DSM, whether exclusively or in conjunction with other measures, is an acceptable operating procedure for use in a Corrective Action Plan, as long as the Transmission Owner demonstrates availability and accuracy of DSM data and its viability as an operating procedure for each applicable scenario.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒

Comment: Incremental benefits do not justify the magnitude of additional studies. Corrective Action plans should be tested, but not as a new study with all of the Corrective Action Plans included simultaneously. The proposed language is inferior to the existing language (TPL-002-0 R2) and suggest replacing with language from TPL-002-0 R2.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒

Comment: All projects should be called "Planned" projects. There is no distinction in a model between committed and proposed projects that would treat them differently. They are either in the model or not in the model. This sub-requirement does not follow the major requirement wording in R2.7 ".....Such plans shall:" The intent of Requirements R2.7.3 and R2.7.4 should be combined and added into R2.7.1.1. Rather than adding the addtional requirement to document a criteria, the requirement should be that in the Near-Term Planning Horizon, projects cannot be removed (or modified) without demonstrating that the revised plan meets performance criteria. Suggested wording for R2.7.1.1. "Transmission and generation improvement projects for the Near-Term Transmission Planning Horizon, shall have in-service dates provided (to whom?), and shall not have in-service dates changed, or be removed from planning models, without documentation to show that the revised plan meets performance requirements."

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒

Comment: All projects should be called "Planned" projects. Additionally, see response to question 18.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	This loss is currently distinguished from other single contingencies because of its lower probability of occurrence and a more stringent performance requirement than currently exists is not warranted.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Systems have been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis. In addition, by not allowing loss of non-consequential load, the system may remain in a less secure state or condition.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Systems have been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis. In addition, by not allowing loss of non-consequential load, the system may remain in a less secure state or condition.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	Systems have been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis. In addition, by not allowing loss of non-consequential load, the system may remain in a less secure state or condition.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒

Comment: This loss is currently distinguished from other single contingencies because of its lower probability of occurrence and a more stringent performance requirement than currently exists is not warranted.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: Systems have been designed such that Multiple Contingency events (N-2) above 300 kV may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis. In addition, by not allowing loss of non-consequential load, the system may remain in a less secure state or condition. This new category P3-1 is essentially a replacement for Category C5-9 except the only protection element failure to be considered is the failure of a circuit breaker to open. This definition eliminates the need to examine failure of the relay to operate which in many cases has a more serious impact on grid reliability.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of another generator would not result in Non-consequential Load Loss, and equipment ratings would not be exceeded etc. However, the initial state of the system must be clarified in all performance table scenarios (including P4-1).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1-1 events.
Q27. P4-2: Loss of a generator followed by a	☐Agree.	Systems should be planned such that the loss of a generator, followed by

[1] System adjustment can be manual or automatic

System adjustment followed by the loss of a monopolar DC line	☒Do not agree.	System adjustment, followed by the loss of another generator would not result in Non-consequential Load Loss, and equipment ratings would not be exceeded etc. However, the initial state of the system must be clarified in all performance table scenarios (including P4-1).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1-1 events.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of another generator would not result in Non-consequential Load Loss, and equipment ratings would not be exceeded etc. However, the initial state of the system must be clarified in all performance table scenarios (including P4-1).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1-1 events.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of another generator would not result in Non-consequential Load Loss, and equipment ratings would not be exceeded etc. However, the initial state of the system must be clarified in all performance table scenarios (including P4-1).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1-1 events.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒

Comment: The proposed standard does not distinguish between asynchronous DC ties and the more common parallel connected DC tie. With an asynchronous DC tie, the transfer is lost with the tie. With a parallel DC tie, the transfer will be shifted to the parallel AC system, therefore, AC lines should have the same performance criteria as DC lines.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☒

Comment: The separation of steady state and dynamic response analysis requirements into two tables (with different contingencies) is inferior to the analysis requirements outlined in Table 1 of the existing TPL Standard. The structure of Table 1 reinforces the requirement for grid stability and maintaining the grid within applicable limits for Category B and C contingencies. Dynamic simulations of Category B and C contingencies that demonstrate grid stability should be followed up with post transient power flow analysis to assess voltage and thermal limits.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒

Comment: There should be no such distinction. All stability studies must meet the Performance Requirements for Planning Events in Table 2 - Stability Performance. If there were different Performance Requirements then the distinction may be warranted. However system stability studies should be sufficient and not warrant additional work.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment: The question does not match what is included the Extreme Events section of Table 2. Loss of all generating units at a plant should be considered in the Steady State Performance - Extreme Events but not in the Stability Performance - Extreme Events because of the very low probability of the event ocurring within the timeframe of the Stability simulation. Therefore, the performance requirement number 9 for Extreme Events in Table 2 - Stability Performance should be deleted.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load

model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒

Comment: The issue of delayed voltage recovery is a special phenomenon that can occur in some large urban areas under peak conditions. The modeling of the delayed voltage recovery response is considerably more complex than simply representing induction motor effects. The scope of the delayed voltage recovery issue is extremely limited and its effect on the grid is generally self correcting due to automatic disconnection of the affected air conditioners. While improvements in the accuracy of load models used for the study of grid dynamic response are desireable, this area is not suitable for compliance enforcement. Requirements for specific types of load models are not appropriate in the TPL standard.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Manual and automatic adjustment (increase or decrease) of Var output and manual and automatic tripping or reduction of overall MW output of generators should be allowed.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: At a minimum the emergency ratings should allow sufficient time for the runback scheme to operate reliably.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: The performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. If the proposed TPL standard is adopted the contingency references in PRC-012-0 would need to be updated.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: The performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. If the proposed TPL standard is adopted the contingency references in PRC-012-0 would need to be updated.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: The performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. If the proposed TPL standard is adopted the contingency references in PRC-012-0 would need to be updated.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment: No, if the comments to the above questions are incorporated. The FRCC system is a peninsular system having only one interface with the rest of the interconnected NERC system, and has historically demonstrated exceptionally high reliability with no events in recent history cascading beyond the FRCC system. The adequacy of the existing TPL standards as they apply to the FRCC System have been extensively documented.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment: General Comment: NERC Standards TPL 001-0 through TPL 004-0 are approved standards that only required modifications pursuant to FERC Order 693. In this proposed draft standard TPL 001-1 the Standard Drafting Team (SDT) has far exceeded the recommendations suggested by FERC in that Order as well as created unnecessary confusion. FPL believes that the SDT's decision to combine NERC Standards TPL 001-0 through TPL 004-0 into one standard was not a specific requirement by FERC Order 693 and may not have been a good decision by the STD, therefore it should be reconsidered after reviewing all of the comments. At a minimun, the team should somehow clearly demonstrate changes in the standard's wording and required performance levels as compared to the existing standards. The new proposed draft of TPL-001 creates unnecessary confusion and interpretation of new ambiguous language, which is inconsistant with the stated objectives, instead of providing clarity to the standards. As an example of how to provide additional clarity, the existing standards have unnecessary redundancy in the tables, for example, it would have been nice to clean up (clarify) the tables such that the table for TPL-001 would only contain the performance criteria for Category A, with footnotes only applicable to that category, clarified as directed by FERC in Order 693. Similarly, TPL-002 would only contain performance criteria for Category B, and so on.

In addition to combining the standards, the SDT has significantly changed contingency specifications and required performance levels. In many cases the changes represent a very significant increase in required performance standards that will require unjustified major capital expenditures and/or reductions in ATC. This also could have an adverse impact on commercial transactions. In other cases, the performance criteria are not clearly defined, such as the timing between multiple contingencies, and the level of readiness of the system after Planning Events. The benefits from the additional performance requirements have not been identified in the proposed standard. Is there a planned phased in approachto move from the existing standard to the new proposed standards. If so, what is it?

Finally, the SDT has chosen to eliminate the footnotes in the current standards, contrary to the direction of FERC in Order 693 to "clarify" the footnotes. The purpose of the footnotes is to further explain terms in the tables, provide guidance in interpreting the expected performance criteria, and specify any exceptions to the criteria. Footnotes also serve the purpose of keeping the standard concise by eliminating repetitiveness.

Specific comments on the Draft Standard

Performance Criteria

The performance requirements table should clearly define what the initial state of the system is assumed to be before any Planning Events, and what the state of the system is assumed to be after the Planning Event. For example, P1 (single contingency) events: assuming that the system is to be compliant, the state of the system prior to the event must be "secure" such that the event could occur and there is no interruption of firm transfer or loss of load, Equipment Ratings are not exceeded, System steady state voltages and post-transient voltage deviation are within acceptable limits. However, the system is not as it was before the event. The system could be described as "normal" but perhaps not "secure". If the requirement is that the system must also be "secure" after the event, then the standard must clarify what is allowed for "system adjustments" after the first Planning event to prepare for the next. FERC Order 693 directed the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency. However, in order to bring the system to a secure state, as is necessary for the second contingency of a category C3 or C5 event, footnote (c) allows curtailment of firm transfers, and FERC Order 693 only required footnote (c) to be clarify the term "controlled load interruption", leaving the curtailment language intact. The implication of this interpretation is critical to peninsular Florida. The Category B loss of one 500 kV line from Florida to Georgia is sustainable, such that the system is "normal" after the event. However, in order to be prepared for the next contingency, (the loss of the second 500 kV line), firm transfers must be curtailed. (Interruption of Firm Transfer) Without the ability to curtail firm transfers, a "super-firm" priority of service is created, which is unjustified.

Comments on New Performance Tables:
The draft TPL standard represents a major change in the Table 1 contingency definitions and required performance levels.

Table 1 Contingencies C1 and C2 are being moved to the single contingency category. While C1 and C2 represent single element outages, their probability of occurrence is much lower than the other Category B contingencies and they do not belong in the single contingency performance requirements group.

Footnote (b) which permits, as a limited exception in unique circumstances with a sound rational basis, some localized load reduction for single contingencies, has been removed. This is a very significant change for some utilities. Footnote (c) which permits load shedding and curtailment of firm transfers has been removed from C1, C2 and most of C3. This is a very significant increase in required performance level that is not justified.

The "applicable rating" for loading and voltages in Table 1 has been removed so that essentially, the same ratings and voltage restrictions apply to both B and C contingencies. Some utilities plan to a normal rating for single contingencies but will allow a higher short term rating for Category C events. This practice will apparently be disallowed.

Several new Category D "extreme events" have been added which greatly expand the scope and complexity of Category D studies. These are (1) any two unrelated single element outages and (3) wide area events a. through h. These represent a major increase in the scope of Category D studies and probably a doubling of required SWG studies.
The fault with protection element failure categories D1 through D4 have been substantially changed to eliminate analysis of relay failure contingencies. The philosophy contained in the existing TPL-004 standard is that faults with a protection failure should be evaluated whether that failure is a circuit breaker, relay or CT; the proposed standard restricts the analysis to breaker failure.

300 kV Threshold Performance Level
The TPL-001-1 draft sets a threshold of higher performance to facilities above 300 kV than previously established in the existing standard. We do not agree that such a threshold is necessary or warranted nor have they been justified. Requirements which are more stringent for these facilities may wrongly influence decisions on project alternatives in favor of facilities with less stringent requirements.

DC Line Performance Requirement
The TPL-001-1 draft sets a lower performance requirement for the loss of a single pole of a DC line than in the existing standard by allowing interruption of firm transfer if the transfer is deemed to be dependent on the outaged line. Firm transfers are also dependent upon AC lines. The proposed standard does not distinguish between

asynchronous DC ties and the more common parallel connected DC tie. With an asynchronous DC tie, the transfer is lost with the tie. With a parallel DC tie, the transfer will be shifted to the parallel AC system and should have the same performance requirements. We do not agree that such an exception for DC lines is necessary or warranted. The decision in selecting DC vs. AC in transmission lines has traditionally been based on the break-even cost and performance of the two alternatives. The lower performance requirement may wrongly influence decisions on project alternatives in favor of DC facilities with less stringent requirements.

Distinction Between Committed and Proposed Projects:
Models cannot discern the difference between a "committed" project, and a "proposed" project in a performance analysis. The standard should instead set criteria for when models can be relied upon for planning purposes such that changes to the future plan will not have an impact on reliability. The intent of Requirements R2.7.3 and R2.7.4 should be combined and added into R2.7.1.1. Rather than adding the additional requirement to document a criteria, the requirement should be that in the Near-Term Planning Horizon, projects cannot be removed (or modified) without demonstrating that the revised plan meets performance criteria. In addition, the requirement in R2.7.1.1 to supply a "project initiation date" is ambiguous. What will constitute "project initiation" …construction start date? …Engineering complete date? …Land procurement date? Funds allocated date (budgeted)? Suggested wording for R2.7.1.1. "Transmission and generation improvement projects for the Near-Term Transmission Planning Horizon, shall have in-service dates provided, and shall not have in-service dates changed, or be removed from planning models, without documentation to show that the revised plan meets performance requirements." In addition to the concerns mentioned above, how are delays in meeting project in-service dates, which are not in the direct control of the Transmission Owner, caused by siting and Right of Way difficulties (public outcry, exercising eminent domain, court process, etc) addressed? The standard needs to have provisions to recognize these types of issues allowing a Transmission Owner to be compliant as long as he is using due diligence to overcome these types of delays.

Analysis of Relay Protection Failures:
This draft of the TPL standard ignores studies required for analysis of relay protection failures. There is a widespread misconception that studying breaker failure scenarios covers for relay protection failures. This is a false assumption. Typical delayed clearing for a stuck breaker is in the order of 8 to 20 cycles. This is accomplished by the local relay system sensing the stuck breaker and tripping the adjacent elements. However in the case of a protective relay failure the fault must usually be cleared remotely by tripping all lines connected to the station. Typical delays for a relay failure can easily be greater than 30 cycles. Where as breaker failure action just trips a couple of adjoining elements and leaves the rest of the station intact. A typical example of this difference is to assume a bus fault. For breaker failure, all bus breakers except the stuck one would trip. The breaker failure relay scheme then would time out and trip the adjoining breaker and the remote end of the adjoining line would trip. This could all happen in less than 20 cycles. Now consider a bus fault with the differential relay failed. The local relays don't sense the fault because they have failed, nor does the local breaker failure scheme activate because no local detection has occurred. The only way to clear this fault is to trip all lines from the remote terminals. This may take 30 cycles or more. With breaker failure, the bus and one line trips in about 20 cycles. With relay failure, all lines trip remotely isolating the substation in about 30 cycles. Both scenarios must be studied with relay failure being the worse case. Generally, different solutions are required to address relay failure verses breaker failure.

Load Modeling Requirements:
The proposed TPL Standard contains numerous references to load modeling. The goal of improving and verifying the load model is worthwhile but is not appropriate for the TPL standards. Assessment of load model accuracy is best accomplished through detailed analysis of grid disturbance events. The main difficulties in accomplishing this are (1) grid events that significant reduce transmission voltages throughout a load area are infrequently occurring and (2) the process of Recreating the event through simulation studies is extremely complex and time consuming. While these efforts should be encouraged they should remain a RRO prerogative.

R1.1.1 Use of expected Load mix based on the actual or expected aggregate mix of industrial, commercial, and residential Loads. – This requirement is not justified as the load model may be developed through disturbance analysis rather than load type synthesis by customer class. Some LSE's may have great difficulties in creating load forecasts based on customer class. Load forecasting requirements are adequately addressed in the existing MOD standards and do not belong in the proposed TPL standard.

R1.2. Load models with supporting rationale that include power factor data that may be based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements. This requirement is not appropriate fot the TPL standarsds.

R2.4.1. System peak Load for one of the five years. For peak System Load levels, the Load model shall include the dynamic effects of induction motor Loads.

Specific types of load models should not be required in this standard.

Short Circuit Requirements: The new TPL standard also contains numerous references to short circuit analysis, which are new requirements that expand the TPL standards, but without specific testing or performance criteria. Evidence that short circuit studies have been performed is currently required in the existing FAC-002-0 Standard. Since the primary concern is the appropriate sizing of equipment and the prevention of equipment damage as opposed to overall grid reliability, we do not see the need for a set of requirements within the proposed TPL standard for short circuit studies.

Given the aforementioned issues, we believe the proposed TPL standard is inferior to the existing Board approved TPL Standards, creates unnecessary confusion, and will require many iterations of industry comment and revision. As an intermediate approach, we would strongly urge the Standard Drafting Team that the existing TPL standards be modified to respond to FERC Order 693 directives, clarify any ambiguities, and not pursue the proposed new standard any further. This would bring a much needed part of the Reliability Standards into the framework of mandatory enforcement and provide guidance on this longer term effort to improve the TPL standards.

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: **FRCC**

Lead Contact: **Vicente Ordax**

Contact Organization: **FRCC**

Contact Segment: **10**

Contact Telephone: **813-207-7988**

Contact E-mail: **vordax@frcc.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
W. R. Schoneck	Florida Power & Light Company	**FRCC**	3
Earl Fair	Gainesville Regional Utilities	FRCC	1
Keith Mutters	Orlando Utilities Commission	FRCC	3
Donald Gilbert	JEA	FRCC	5
Gary Brinkworth	City of Tallahassee	FRCC	1
C. Martin Mennes	Florida Power & Light Company	FRCC	1
Robert A. Birch	Florida Power & Light Company	FRCC	5
John W. Shaffer	Florida Power & Light Company	FRCC	3
Ronald L. Donahey	Tampa Electric Company	FRCC	3
A. L. Barredo	Florida Power & Light Company	FRCC	3
Lee Schuster	Progress Energy Florida	FRCC	3
Bart White	Progress Energy Florida	FRCC	3
Paul Elwing	Lakeland Electric	FRCC	5
Richard Gilbert	Lakeland Electric	FRCC	3
Larry E. Watt	Lakeland Electric	FRCC	1
Paul Shipps	Lakeland Electric	FRCC	6
Thomas J. Szelistowski	Tampa Electric Company	FRCC	1
Fred McNeill	Florida Reliability Coordinating Council	FRCC	10
Ted E. Hobson	JEA	FRCC	1
Gary Baker	JEA	FRCC	3

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the

rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: "Computer" is not appropriate. Replace with "Data model" or "Database model". The last sentence is not clear as to what type of ratings (i.e., normal, short-term emergency, long-term emergency, etc.). Suggest removing sentence completely or rewording as follows: "... in accordance with the documented methodologies required by FAC-008 for each Transmission Owner and Generator Owner."**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: Need to clarify what constitues an element (e.g., breaker-to-breaker, line segment to line segment, transformer or capacitor bank)**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Reword as follows: "Events which are more severe and have a lower probability of occurrence than planning events."**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☒Do not agree.
Q4. **Comment: The definition does not have a reference year when the counting starts. Add the following to the end of the sentence: "... from the current study year."**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree.

	☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: Reword as follows: "Firm load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems, excluding (arranged or contracted) curtailments, DSM, and voltage reduction."**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Last part of the last sentence should be removed "… and other factors, such as asset conditions and age" does not make sense for planning studies. Equipment condition and age are maintenance issues not transmission planning issues.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: There should be no distinction between Plant Stability and System Stability. All stability studies must meet the Performance Requirements for Planning Events in Table 2 - Stability Performance. If there were different Performance Requirements then the distinction would be warranted.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: Dynamic voltage ratings are most often used as a proxy for lack of relay models or other modeling limitations. The definition should not address performance and should only seek to define the term. Reword as follows: "Study of the System or portions of the System to assess angular Stability and inter-area power oscillations."**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the	☐Agree. ☒Do not agree.

study publication are assumed to be conducted under the auspices of Operations Planning.	
Q11. **Comment: The last sentence of this definition is not included in the Standard and should be deleted.**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: Not all Regions' concerns are the same and therefore each Region should determine which sensitivities are appropriate.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The Transmission Planner needs the flexibility to define what are considered "reasonably stressed" cases for their respective systems. This would not a be a proper application of a one size fits all definition.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒

Comment: The standards require near term base case cases to be studied for a broad range of planning and extreme events. The sensitivity analysis requirements contained R.2.4.3. will essentially require every dynamic simulation to be run at least twice regardless of whether or not there is any engineering insight to be gained. While improved understanding may result from sensitivity analysis of certain key event scenarios, the overall benefits of the sensitivity study requirements contained in section R.2.4.3 do not justify the huge increase in engineering effort to conduct and document these simulations with minimum to no increase in reliability.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: If DSM is included as part of an integrated Corrective Action plan, then the impact of DSM should be included by specifying the location and expected quantity of DSM that will mitigate a system deficiency. Should be permitted only if the tariff allows it and the magnitude is appropriately identified at each load bus. DSM response is limited to transmission provider's territorial customers. The use of DSM, whether exclusively or in conjunction with other measures, is an acceptable operating procedure for use in a Corrective Action Plan, as long as the Transmission Owner demonstrates availability and accuracy of DSM data and its viability as an operating procedure for each applicable scenario.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒

Comment: Incremental benefits do not justify the magnitude of additional studies. Corrective Action plans should be tested, but not as a new study with all of the Corrective Action Plans included simultaneously. Suggest replacing with language from TPL-002-0 R2..

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒

Comment: All projects should be called "Planned" projects. There is no distinction in a model between committed and proposed projects that would treat them differently. The standard should instead set criteria for when models can be relied upon for planning purposes such that changes to the future plan will not have an impact on reliability. The intent of Requirements R2.7.3 and R2.7.4 should be combined and added into R2.7.1.1. Rather than adding the additional requirement to document a criteria, the requirement should be that in the Near-Term Planning Horizon, projects cannot be removed (or modified) without demonstrating that the revised plan meets performance criteria. In addition, the requirement in R2.7.1.1 to supply a “project initiation date” is ambiguous. What will constitute “project initiation” …construction start date? …Engineering complete date? …Land procurement date? Funds allocated date (budgeted)? Suggested wording for R2.7.1.1. “Transmission and generation improvement projects for the Near-Term Transmission Planning Horizon, shall have in-service dates provided, and shall not have in-service dates changed, or be removed from planning models, without documentation to show that the revised plan meets performance requirements.”

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒

Comment: See response to question 18.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to “raise the bar.” Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	This loss is currently distinguished from other single contingencies because of its lower probability of occurrence and a more stringent performance requirement than currently exists is not warranted.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Systems have been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Systems have been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	Systems have been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒

Comment: This loss is currently distinguished from other single contingencies because of its lower probability of occurrence and a more stringent performance requirement than currently exists is not warranted.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: This new category P3-1 is essentially a replacement for Category C5-9 except the only protection element failure to be considered is the failure of a circuit breaker to open. This definition eliminates the need to examine failure of the relay to operate which in many cases has a more serious impact on grid reliability.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of another generator would not result in Non-consequential Load Loss, and equipment ratings would not be exceeded etc. However, the initial state of the system must be clarified in all performance table scenarios (including P4-1).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1-1 events.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of a monopolar DC line would not result in Non-consequential Load Loss, and equipment ratings would not be exceeded etc. However, the initial state of the system must be clarified in all performance table scenarios (including P4-2).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard

[1] System adjustment can be manual or automatic

		performance requirements could be interpreted to require planning for all G-1-1 L-1 events.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of a transmission circuit would not result in Non-consequential Load Loss, and equipment ratings would not be exceeded etc. However, the initial state of the system must be clarified in all performance table scenarios (including P4-3).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1 L-1 events.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of a transformer would not result in Non-consequential Load Loss, and equipment ratings would not be exceeded etc. However, the initial state of the system must be clarified in all performance table scenarios (including P4-4).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1 T-1 events.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒

Comment: DC and AC lines should not be treated differently. System response is similar for the loss of an AC line versus the loss of a parallel connected DC tie. For the loss of a parallel DC tie the transfer is shifted to the parallel AC system in the same manner as a loss of an AC line. The decision in selecting DC vs. AC in transmission lines has traditionally been based on the break-even cost and performance of the two alternatives. The lower performance requirement may wrongly influence decisions on project alternatives in favor of DC facilities with less stringent requirements. Therefore, AC lines should have the same performance criteria as DC lines.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☒

Comment: There are two points of view for this question. One view is that having the persformance requirement for steady state and dynamics on two separate tables is a good idea. It makes it easier to identify the performance requirements for steady state and dynamics. The other view is that separation of these requirements into two tables is not necessary because the existing tables are clear and FERC Order 693 only required the footnotes to be clarified not to redevelop the tables. The structure of existing Table 1 reinforces the requirement for grid stability and maintaining the grid within applicable limits.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒

Comment: There should be no such distinction. All stability studies must meet the Performance Requirements for Planning Events in Table 2 - Stability Performance. If there were different Performance Requirements then the distinction may be warranted. However system stability studies should be sufficient and not warrant additional work.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment: The question does not match what is included the Extreme Events section of Table 2. The draft proposed TPL standard DOES include the loss of all generating units as Extreme Event 9 in Table 2. We agree that it is highly unlikely that all units at a plant would trip simultaneously. The preceding Extreme Event (8. Loss of a switching station - one voltage level) will in most cases adequately represent generating plant outages .

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒

Comment: The modeling of the delayed voltage recovery response that has been observed in some large urban areas during periods of high air conditioning usage is considerably more complex than simply representing induction motor effects. The scope of the delayed voltage recovery issue is extremely limited and its effect on the grid is generally self correcting due to the automatic disconnection of the affected air conditioners. Requirements for specific types of load models are not appropriate in the TPL standard.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Manual and automatic adjustment (increase or decrease) of Var output and manual and automatic tripping or reduction of overall MW output of generators should be allowed.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: At a minimum the emergency ratings should allow sufficient time for the runback scheme to operate reliably.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: The performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. If the proposed TPL standard is adopted the contingency references in PRC-012-0 would need to be updated.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: The performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. If the proposed TPL standard is adopted the contingency references in PRC-012-0 would need to be updated.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: The performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. If the proposed TPL standard is adopted the contingency references in PRC-012-0 would need to be updated.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment: No, if the comments to the above questions are incorporated. The FRCC system is a peninsular system having only one interface with the rest of the interconnected NERC system, and has historically demonstrated exceptionally high reliability with no events in recent history cascading beyond the FRCC system. The adequacy of the existing TPL standards as they apply to the FRCC System have been extensively documented.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: General Comment:

The SDT has significantly changed contingency specifications and required performance levels. In many cases the changes represent a very significant increase in required performance standards that will require unnecessary major capital expenditures and/or reductions in ATC which will have an adverse impact on commerce. Neither of these outcomes is desirable.

Specific comments on the Draft Standard
Performance Criteria

The performance requirements table should clearly define what the initial state of the system is assumed to be before any Planning Events, and what the state of the system is assumed to be after the Planning Event. For example, P1 (single contingency) events: assuming that the system is to be compliant, the state of the system prior to the event must be "secure" such that the event could occur and there is no interruption of firm transfer or loss of load, Equipment Ratings are not exceeded, System steady state voltages and post-transient voltage deviation are within acceptable limits. However, the system is not as it was before the event. The system could be described as "normal" but perhaps not "secure". If the requirement is that the system must also be "secure" after the event, then the standard must clarify what is allowed for "system adjustments" after the first Planning event to prepare for the next. FERC Order 693 directed the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency. However, in order to bring the system to a secure state, as is necessary for the second contingency of a category C3 or C5 event, footnote (c) allows curtailment of firm transfers, and FERC Order 693 only required footnote (c) to be clarify the term "controlled load interruption", leaving the curtailment language intact. The implication of this interpretation is critical to peninsular Florida. The Category B loss of one 500 kV line from Florida to Georgia is sustainable, such that the system is "normal" after the event. However, in order to be prepared for the next contingency, (the loss of the second 500 kV line), firm transfers must be curtailed. (Interruption of Firm Transfer) Without the ability to curtail firm transfers, a "super-firm" priority of transmission service is created for non-native load customers.

Comments on New Performance Tables:
The draft TPL standard represents a major change in the Table 1 contingency definitions and required performance levels.

Table 1 Contingencies C1 and C2 are being moved to the single contingency category. While C1 and C2 represent single element outages, their probability of occurrence is much lower than the other Category B contingencies and they do not belong in the single contingency performance requirements group.

Footnote (b) which permits, as a limited exception in unique circumstances with a sound rational basis, some localized load reduction for single contingencies, has been removed. This is a very significant change for some utilities and this limited exception should be maintained. Footnote (b) was worked on extensive and achieved industry consensus at one time defining the maximum amount of load that could be shed at 100 MW. Footnote (c) which permits load shedding and curtailment of firm transfers has been removed from C1, C2 and most of C3. This is a very significant increase in required performance level that is not justified.

It is not clear what is meant by the phrase "Equipment Ratings" found in the performance requirements of Table 1. Utilities have different equipment ratings such as normal, long term, short term and emergency ratings. It is not clear that these type of ratings will be permitted in the proposed standard.

Several new Category D "extreme events" have been added which greatly expand the scope and complexity of Category D studies. These are (1) any two unrelated single element outages and (3) wide area events a. through h. These represent a major increase in the scope of Category D studies and probably a doubling of required stability studies.

Analysis of Relay Protection Failures:
The fault with protection element failures have been substantially changed to eliminate analysis of relay failure contingencies. The philosophy contained in the existing standards is that faults with a protection failure should be evaluated whether that failure is a circuit breaker, relay or CT; the proposed standard does not require the analysis of any protection failure. This draft of the TPL standard ignores studies required for analysis of relay protection failures. There is a widespread misconception that studying breaker failure scenarios covers for relay protection failures. This is a false assumption. Typical delayed clearing for a stuck breaker is in the order of 8 to 20 cycles. This is accomplished by the local relay system sensing the stuck breaker and tripping the adjacent elements. However in the case of a protective relay failure the fault must usually be cleared remotely by tripping all lines connected to the station. Typical delays for a relay failure can easily be greater than 30 cycles. Where as breaker failure action just trips a couple of adjoining elements and leaves the rest of the station intact. A typical example of this difference is to assume a bus fault. For breaker failure, all bus breakers except the stuck one would trip. The breaker failure relay scheme then would time out and trip the adjoining breaker and the remote end of the adjoining line would trip. This could all happen in less than 20 cycles. Now consider a bus fault with the differential relay failed. The local relays don't sense the fault because they have failed, nor does the local breaker failure scheme activate because no local detection has occurred. The only way to clear this fault is to trip all lines from the remote terminals. This may take 30 cycles or more. With breaker failure, the bus and one line trips in about 20 cycles. With relay failure, all lines trip remotely isolating the substation in about 30 cycles. Both scenarios must be studied with relay failure being the worse case. Generally, different solutions are required to address relay failure verses breaker failure.

300 kV Threshold Performance Level
The TPL-001-1 draft sets a threshold of higher performance to facilities above 300 kV than previously established in the existing standard. We do not agree that such a threshold is necessary or warranted. Requirements which are more stringent for these facilities may wrongly influence decisions on project alternatives in favor of facilities with less stringent requirements.

Load Modeling Requirements:
The proposed TPL Standard contains numerous references to load modeling. These modeling requirements should be addressed in the MOD Standards. The goal of improving and verifying the load model is worthwhile but is not appropriate for the TPL standards. Assessment of load model accuracy is best accomplished through detailed analysis of grid disturbance events. The main difficulties in accomplishing this are (1) grid events that significant reduce transmission voltages throughout a load area are infrequently occurring and (2) the process of Recreating the event through simulation studies is extremely complex and time consuming. While these efforts should be encouraged they should remain a RRO prerogative.

* R1.1.1 Use of expected Load mix based on the actual or expected aggregate mix of industrial, commercial, and residential Loads. – This requirement is not justified as the load model may be developed through disturbance analysis rather than load type synthesis by customer class. Some LSE’s may have great difficulties in creating load forecasts based on customer class. Load forecasting requirements are adequately addressed in the existing MOD standards and do not belong in the proposed TPL standard.

* R1.2. Load models with supporting rationale that include power factor data that may be based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements. This requirement is not appropriate for the TPL standards.

* R2.4.1. System peak Load for one of the five years. For peak System Load levels, the Load model shall include the dynamic effects of induction motor Loads. Prescribing specific types of load models in this standard is not appropriate because system topology and load make up may be unique from area to area.

Short Circuit Requirements: The new TPL standard also contains numerous references to short circuit analysis, which are new requirements that expand the TPL standards, but without specific testing or performance criteria. These performance criteria are better suited in the FAC Standards since evidence that short circuit studies have been performed is currently required in the existing FAC-002-0 Standard. Since the primary concern is the appropriate sizing of equipment and the prevention of equipment damage as opposed to overall grid reliability, we do not see the need for a set of requirements within the proposed TPL standard for short circuit studies.

Table 2 Angular Stability Notes: The requirement of generation loss not exceeding BA spinning reserve requirement (1.a.ii.) is an unjustified increase in required performance level from the existing TPL Standard which require the grid response to be stable and within applicable ratings. The portion of the notes requiring generator out-of-step protection are inappropriate and unwarranted. First, the simulation result may show the generator being tripped by backup distance or loss of field protection which may be acceptable to the generator owner. Second, the requirement for impedance swings not causing other transmission elements to trip is inappropriate and in conflict with manufacturer recommendations and prevailing practice for generator out of step protection. Most generator out of step relays are set to trip on the “way out” so as to limit phase angle difference across the opening contacts. With this practice, one can not prevent transmission line tripping due to zone 1 pickup without installing out of step blocking should the swing impedance passes through zone 1 relay. Out of step blocking of zone 1 relays is a bad idea as it opens the door to prolonged asynchronous connection of generators.

Circuit Breaker Contingencies: The proposed TPL standard separates circuit breaker related contingencies based on the intended use of the circuit breaker. If the circuit breaker is used to connect busses together (i.e. bus tie breaker) a lower level of performance is required than for other uses and configurations. The existing TPL standards have the contingency events and required level of performance appropriately ordered based on the probability of occurrence. We are not aware of different failure rates for bus ties breakers as opposed to the general circuit breaker population. The proposed standard requires an unjustified higher level of performance for non bus tie breakers and would encourage the use of low cost switching station arrangements such as single breaker/single bus which are less reliable.

Need to clarify the performance requirements that apply to sensitivity studies. These requirements should not be the same.

A.3. - Suggest replacing the word "probable" with "credible" for consistency with the white paper from the Operating Limit Definitions Task Force.

R2.1 - It is not clear how the requirement to address all 5 years can be accomplished when the annual studies do not require all 5 years to be studied. Is the planner expected to study the other years also, but that the required set of cases does not link to each of the 5 years?

R2.2.1 - This requirement creates compliance concerns. Therefore, it is suggested that the SDT clarify that the Long Term Assessment is not required beyond 10 years.

R2.7.3 - The term "proposed" may not be a good choice here ... especially since that's not a term used in other reliability assessments .... should another term be chosen or perhaps this definition could be matched up with work being done now on classification of resources for RAS.

Steady State Performance Table:

P1 - If the transmission line outaged is the facility defined by contract as being the only contract path for the firm transfer, then the firm transfer will be interrupted. P1 should be clarified that this is acceptable.

P3 - Are these elements meant to be combined into a multiple contingency or considered separately (since they are listed with commas)? Or is this meant to be one of the 3 elements listed first AND the stuck breaker? Not clear the way this is worded. Or maybe the structure needs to be different in the sentence (like bullets for the first 3 that would make the "and" stick out more).

NERC Standards TPL 001-0 through TPL 004-0 are approved standards that only required modifications pursuant to FERC Order 693. In this proposed draft standard TPL 001-1 the Standard Drafting Team (SDT) has far exceeded the recommendations suggested by FERC in that Order. The proposed draft standard is a large change in the magnitude of the performance requirements from the exiting TPL Standards. The SDT needs to consider how this proposed standard will be implemented in this new mandatory compliance environment and ensure that reasonable compliance measures can be developed from the proposed standard.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization: Georgia Transmission Corporation		
Telephone: 770-270-7824		
E-mail: angela.battle@gatrans.com		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: The base case is also a representation of firm transactions through a BES, generation resources, and models reactive components.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: This definition implies that load that is lost past the directly connected load is allowed. Therefore the definition should be changed to include radially connected load and load that is radialized as a result of a contingency or mis-operation.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: All events on the BES have a low probability of occurrence. Extreme events are those events that have a high consequence to the BES if they were to occur.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such	☐Agree. ☒Do not

as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	agree.
Q6. **Comment: Suggest a change in title to Indirect Load Loss**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Asset conditions and age should not be included in the definition. Equipment replacement, in general, is dependent on performance, not age.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Performance requirements should be added to the definition.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: The first sentence in not necessary. A Planner may use the base case to further assess a problem in the current year. The definition should begin with "The next planning year following current annual studies".**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the

requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: Sensitivity analyses should not be prescribed. In one system there may be various sensitivites based on region, generation location, number of long range projects, etc. The Planner should provide a summary of the critical sensitivities and documentation supporting their definitionis.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: See comment to Q12.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐

Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: The sensitivities should be determined by the Planner. As part of the development of long range projects, sensitivity analyses should be performed.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system

deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒
Comment: DSM should not be a requirement in considering Corrective Action Plans. Because DSM cannot be counted on or controlled, its use as a Corrective Action Plan should not be assumed.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒
Comment: This is the essence of planning. All entities should ensure that Corrective Action Plans address the identified constraints and work within the BES infrastructure. It is not clear what the intent of "new" studies is. Since the evaluation of Corrective Action Plans is part of the planning process, what new studies is this requirement referring to. The determination of the study area should be by the Planner.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: They are inherently treated differently. "Committed" projects are a part of the base assumptions in the base case, while "proposed" projects are evaluated until a point where corporate commitment has been made.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: See responses to Q17 and Q18.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to

clarify the standard, address issues described by FERC, and, in particular, to “raise the bar.” Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	No change from current standards.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	This requirement appears unreasonable for a network system and, particularly, for a series of events. This requirement would be well above current reliability standards. The requirement would also result in higher investment costs for the utilities.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	Not applicable to our existing system
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	Not applicable to our existing system

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒

Comment: The standard needs to clearly define a non-bus tie breaker. It is also not clear whether the focus of the standard is the kV level or the equipment type. A material change to build new facilities would be needed to meet this new requirement.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: A material change to build new facilities would be needed to meet this new requirement.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	

[1] System adjustment can be manual or automatic

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Special Protection Schemes should be allowed for single and multiple contingencies.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Generation curtailment should allow the system to operate within the facility capabilities and should not put the generator at risk of violating its NERC requirements during curtailment.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: None.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: PRC Standards

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:
R1.4: The planning assessment is to identify the needs of the BES. A spare equipment strategy should support the needs of the BES, not vice versa. Long-term outages need to be defined.

R2.2.1 Not clear on the purpose of this requirement. Is the concern that the Planner perform a ten year analysis even when the in - service years are outside of the current ten-year planning horizon? The extension period should be defined.

R3.2 Current models do not have the capability of performing the assessments necessary to meet this requirement.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Roger Champagne	
Organization:	Hydro-Québec TransÉnergie	
Telephone:	514 289-2211, X 2766	
E-mail:	champagne.roger.2@hydro.qc.ca	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ ERCOT	☒	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs and ISOs
☐ MRO	☐	3 — Load-serving Entities
☒ NPCC	☐	4 — Transmission-dependent Utilities
☐ RFC	☐	5 — Electric Generators
☐ SERC	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ SPP	☐	7 — Large Electricity End Users
☐ WECC	☐	8 — Small Electricity End Users
☐ NA – Not Applicable	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)			
Group Name:			
Lead Contact:			
Contact Organization:			
Contact Segment:			
Contact Telephone:			
Contact E-mail:			
Additional Member Name	**Additional Member Organization**	**Region***	**Segment***

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: There are a two undefined terms in this definition: "Transmission System" and "interconnected Transmission System". The definition needs to specifically identify what should be modeled applicable to the subject area and in a manner consistent with other NERC definitions. The definition refers to Facility ratings rather than the general reference to FAC-008 & FAC-009**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☒Do not agree.
Q2. **Comment: ``directly-connected`` load loss would be more clear**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Modify to "Events which are more severe,but have a lower probability of occurrence, than Planning Events".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such	☒Agree. ☒Do not

as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	agree.
Q6. **Comment: A better name for this would be "indirect load loss".**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Eliminate "capital" from the definition. It is not defined or consistently applicable to the standard. Reference too vague "other factors, such as asset conditions and age" should be removed from this standard; there are no consistent definitions or industry standards on which to base this requirement, nor does it appear to be a necessary addition to the standard.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Propose, "Events for which Transmission performance requirements must be met".**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: See comment on Q9; proposed modification, "Study of the System or portions of the System to determine whether system angular Stability is maintained, power oscillations are damped, and voltages during the dynamic simulation stay within acceptable perfomance limits.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☒Do not agree.
Q11. **Comment: Modify to, "The first year that a Tranmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner completes and communicates its annual studies."**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement to develop action plans in accordance with consequences of problems highlighted as a result of one of the sensitivity case study.

Suggest modification to, "…sensitivity testing that stresses the System shall be considered, and documentation with the rationale for the sensitivity testing shall be supplied. The sensitivity case(s) may include one or more of the following conditions:"

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement to develop action plans in accordance with consequences of problems highlighted as a result of one of the sensitivity case study.

Reasonably stressed conditions are dependent upon the study area under review and the standard is not likely to be able to be crafted to provide sufficent and consistent direction. However, it might be helpful if the standard clarified whether the base case should include any unplanned generator outages or whether, aside from potential sensitivities, unplanned generator outages are considered only through P1, P3 or P4 Contingencies. If the standard addresses unplanned generator outages only through P1, P3 and P4, then it is recommended that a mandatory sensitivity analysis, with required mitigation, include various potential combinations of a reasonable amount of unplanned outages. The combinations should be based on the part of the system that is under study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐

Comment: The standard is unclear whether or not it mandates the requirement to develop action plans in accordance with the consequences of problems highlighted as a result of one of the sensitivity case study.

Suggest modification to, "…sensitivity testing that stresses the System should be considered. Sensitivity case(s) might include among the following conditions:" 2.4.3 shold mimic 2.1.3 except in regard to load models.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: There is no need for sensitivity analysis.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: DSM should be included to the extent that its performance is sufficiently and consistently understood. The standard does not use the term "optimal" Therefore, the Drafting Team appears to be interpreting the Standard to require a vertically-integrated Planner to produce a so-called optimal-mix of resources plan. This would be an incorrect assumption and is not required. In areas with independent planners and competitive wholesale markets, it is sufficent to identify system needs and produce a plan that identifies regulated transmission solutions in the event that market-based resources (such as DSM) do not address those identified needs. Therefore, while DSM can be as effective a resource as generation, per Commission Orders, in areas with ISOs/RTOs and a competitive wholesale market, the NERC Standard cannot prescribe the development so-called optimized (as is suggested by the Drafting Team) resource-mix plans, as identified by a central planner.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: The study area should be based upon planning expertise and knowledge of the system, giving due consideration to external impacts.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: They should be viewed differently in the Near-Term.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: It is unclear as to what the committed project is being removed from. Suggested language "…removed from the plan…".

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to “raise the bar.” Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☒Do not agree.	The term "bus section" needs to be clarified. Some examples should be given showing actual diagram of substation layout.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Given the low probability of extended overlapping outages of overhead facilities, systems have been designed assuming that load shedding following the loss of a second transmission line is permissible. Eliminating any allowance for load shedding for this condition may require significant system expansion and cost to to customers.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐

Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of 2 additional generators.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a monopolar DC line
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a Transmission circuit
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a transformer

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐

[1] System adjustment can be manual or automatic

Comment: This should also apply to firm transfers via single or double ac facilities as well. In either case, the transfer could be linked to dedicated facilities.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☒

Comment: The contingency studied are the same and as a result should be combined into one table. Only the performance might be different.

We understand the need to clarify the different requirements in the steadystate vs. the stability analyses. However, for each contingency category we expect to see both the steady-state requirements and the corresponding stability requirements in the same table. We believe that it would be better to recombine the steady-state and stability tables and present the information in a landscape format.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒

Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment: Difficult to envision how such an event would occur.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒

Comment: This requirement is too specific and limited. Induction motors are only one component of a complex load model. Complex load models are not always necessary, nor are they always the most conservative, depending on the analysis that is being conducted. Where complex load models are required, they should be considered; this may involve use of complex motor and lighting loads or polynomial load representations

with or without frequency dependence. This question also suggests the need for an industry standard regarding transient voltage recovery.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Manual or automatic adjustments should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment. Manual system adjustment should be allowed in between the multiple Contingencies described in P5, provided that the adjustment can be made between contingencies using short-term reserves (10-30 minute).

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: Generation runback should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐

Comment: However, this should only be allowed where failure of an automatic runback that is not functionally redundant would not have significant adverse impact on the Bulk Power System.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: A SPS may be used to provide protection for infrequent contingencies, or for temporary conditions that may exist such as project delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages. An SPS may also be applied to preserve system integrity in the event of severe facility outages and extreme contingencies. The decision to employ an SPS shall take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: See response to Q38.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: System must remain stable with acceptable voltages and all equipment within applicable emergency limits.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☒
Comment: Until section R3.6.1 is finalized, we will be unable to determine whether a regional variance is required.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:
We think that the proposed fusion of previous TPL-001 to TPL-004 and the addition of more specific contingencies involves too much change at once. It would have been better to make specific change to each individual standards. That way, it would have been more practical to evaluate the impact of the proposed changes.

A major concept before evaluating the impact of a standard is to know on what system it will be applied to. In the tables, the notion of a voltage treshold (>300 kV) is introduced. It is our interpretation that the standard as drafted applies only to BPS elements part of that treshold (>300 kV) and not every ">300 kV" element. The SDT should indicate if they have the same interpretation as ours.

We reiterate our comment that it would be preferable to have only one table that would include both steady state and stability contingencies with their respective expected performance.

There might be some protection standards that would need to be developped/clarified before some proposed changes in this standard.

The SDT has made an effort to define Base Case, yet has not used the term in the standard. At a minimum, Base Case should be referred to in sections 2.1.1, 2.1.2

R.1.1 Load forecasts should be addressed in MOD standards, not TPL.

R 1.4 This should only refer to known long-term outages, not planned outages. Delete "including protective relays"; this is addressed through other provisions.

R2.1, 2.2, 2.3 & 2.4 – The initial paragraph should have identical language regarding ‘annual’, and ‘current or past’ aspects.

R2.1 There should not be a requirement to look at years one and two; a 5 year study should be sufficient. If there has been an ongoing 5 year study, there should be no major unexpected problems occurring in years 1 and 2. Studies of earlier years should only be required if an unanticipated event occurred that had not been considered in prior studies. The TPL should not address shorter term "Operating Studies" or operating issues.

R 2.2.1 Modify to "If any known projects have a lead time that is longer than ten years, the Planning Assessment shall be extended accordingly."

R 2.6.1 Remove reference to "market structure changes". The purpose of its inclusion is unclear.

R 2.7.1.1 Project initiation date should be deleted. If it is retained, it needs to be defined.

R 3.2.1/R 4.3 - What is the intent of this requirement? There should probably be an MOD associated with Generator Owner requirement to provide related generator protection/ limiter data or other plant information.

R 3.4/R 4.5.2 Remove the requirement to implement changes to reduce or mitigate the likelihood of such consequences of Extreme Events. This may not be reasonable or achieveable.

R 3.2 Sectionalizing schemes shall be considered when reflecting the post-contingent system.

R 3.3.2.1 - Proposed deleting "expected duration". This would be dependent upon the damage to the element due to the iniating event and other factors.

R 3.3.3 - Change introductory language to read "Those multiple Contingencies that are…"

R 3.5 - Generation tripping should be allowed as well as generation run-back. In addition, all performance requirements shall be met, rather than just meeting facility rating requirements. Suggested language "Manual and automatic generation run-back and/or generation tripping is allowed as a response to single and multiple Contingencies as long as the performance requirements of this standard are met." If these changes are accepted, R 3.6 can be deleted.

R 4 and R 4.1 - The language should be made similar to R 3 and R 3.1.

Suggest bringing language similar R4.4 into the R 3, the steady state section.

R 4.2 - High speed automatic reclosing schemes shall be considered.

R 6.2 - Change to read "Transmission Planners of neighboring areas".

Table 1 3 b and c Extreme Event descriptions are vague concepts that cannot be practically simulated. 3 d and e are not reasonable or practically useful to simulate.

Table 1, P8 - Language needs to be clarifed as to how the 300 kV threshold is to be treated for transformers. Is this for the high side, low side, or both sides? P5 is much clearer.

Table 2 P9. Recommend that this be changed to require that faults should be on different phases of each of two adjacent transmission circuits on a multiple circuit transmission tower

Table 1, P9(6) and Table 2 P9 - It is unclear as to what is meant by "A spare transformer inserted to replace an outaged transformer followed by System adjustments". Unclear as to what is to be tested.

General comment - Transmission System is used throughout the document and is an undefined term, both "Transmission" and "System" are defined NERC terms. We recommend that the SDT use the term "System" to replace "Transmission System". System is defined as "A combination of generation, transmission, and distribution components".

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**	
Name:	Ron Falsetti
Organization:	IESO
Telephone:	905-855-6187
E-mail:	ron.falsetti@ieso.ca

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment: The proposed definition fairly reflects the starting point system model used for planning and operations studies.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment: This is the same understanding of the IESO.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: We offer alternative wording to more accurately reflect the lower probability of extreme contingencies than their Planning counterparts, as follows:** **Events which are more severe and have a lower probability of occurrence than Planning Events.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment: Consistent with the IESO's understanding.**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: Same as above.**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs	☐Agree.

through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Do not agree.
Q6. **Comment: Suggest to either stop at "automatic operations" or to include other examples since the list is not exhaustive, for example: load that drops out due to unacceptable voltage levels (not tripped intentionally by UVLS.**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☒Do not agree.
Q7. **Comment: The definition covers too much detail on the "how" part, and the "documented" qualifier doesn't seem to be required. Suggest to change it to: Evaluation of future Bulk Electric System needs to meet forecast demand under the assumed system conditions for the time frame studied.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Linking it to Transmission system performance requirements presents "loop around" argument. Suggest to change it to: Events which need to be considered and simulated in planning assessments to evaluate Transmission system performance.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Suggest to replace "Contingencies" with "Planning events", and change the definition as follows:** **Study of an individual generating plant's capability to remain in synchronism and exhibit damping of the generating units' power oscillation for various Planning events.** **Note that "in the vicinity of the plant" is removed to not restrict simulations of events only in the vicinity of the plants as experience has shown that an event remote from the plant could also subject the plant to lose synchronism and/or oscillate without acceptable damping.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: This definition contains requirements that the system must exhibit acceptable performance. The study itself is a tool to assess how the system behaves when subject to Planning events. Suggest to change it to:** **Study of the System or portions of the System to assess the System's performance in the domain of angular Stability, inter-area oscillations and voltage profile during dynamic simulation.**	

Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: Not sure why we need this definition. The standard can simply be worded such that a Transmission Planner is responsible for assessing system needs for time frame beyond the current year. Introducing Operations Planning creates confusion as it is unclear whether this term describes a function or an entity in the context of the proposed definition. Further, the sentence "Analysis conducted for time horizon within the current year from the study publication are assumed to be conducted under the auspices of Operations Planning" is (a) confusing time frame wise, (b) invites debates on the role and responsibility for a term that is not defined in NERC standard or the Functional Model, and (c) is perceived to be prescriptive in organizational setup/responsibility allocation (e.g. why can't a transmission planner conduct operational planning studies?).**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: We do not support introducing sensitivity testing as requirements in the standard, let alone specifying the number of sensitivity cases that need to be developed.

In general, there are two interpretations of sensitivity testing - the type to assist in scoping out planning studies and the type to test the stretched capability of the proposed plans. In the first case, sensitivity testing is conducted to assist in identifying restricting parameters/phenomena, critical faults, and scoping out the conditions that need to be assessed, etc. As such, the scenarios to be included in sensitivity testing vary from one Transmission Planner to another depending on local needs and system characteristics, and even from one study to another for the same area to be assessed. The scope of sensitivity testing is therefore difficult to pin down.

In the second case, while variations such as percentage of forecast peak demand can be picked as a common parameter for sensitivity testing, the follow-on actions, or inactions, after obtaining the test results would be at the sole discretion of the Transmission Planner unless they are specifically addressed by reliability standards. Requiring a Transmission Planner to conduct sensitivity testing, and even to require it to study a specific number of cases case may put a Transmission Planner in a quandary. For example, if sensitivity testing for a case with 5% higher than forecast peak load shows that the system needs a new 500 kV line in a certain area, should the Transmission Planner propose the new line? If so, what are the reliability and economic justifications when it is clearly demonstrated that the line is needed only if the load for that studied time frame turns out to be 5% higher than forecast? If the answer is yes (to propose adding the line), then why don't we simply require that all planning studies assume a condition that is more conservative than that forecast, and stipulate these conditions in the standard accordingly? If not, will the Transmission Planner be criticized for not taking proactive action to manage the potential risk?

Similarly, a Transmission Planner is faced with a much wider study scope if it is required to study the condition assuming one or more major transmission facility is unavailable due to forced outages. These scenarios are more aptly addressed in operations planning or near operations time frame when transmission facility and other system conditions become more predictable. Studies conducted well in advance of real time already rely on many enabling assumptions. Introducing a requirement for sensitivity testing and with specific number of test cases would render the study task difficult to manage, and may put the Transmission Planner in a quandary dealing with the test results. If the standard should require a Transmission Planner to study up to one transmission facility out of service, then this requirement should be clearly stipulated.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a “reasonably stressed” case?

Yes ☐ No ☒
Comment: See comments above. Also, the term "reasonably stressed" is not measurable.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒
Comment: For similar reasons stated in Q13, above.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: We agree, but this raised a question on why did the SDT introduce a requirement for sensitivity testing for year one to year 5 studies but not the year 6 and beyond studies. Wouldn't the degree of uncertainty be higher in the longer time frame?

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒

Comment: No, the amount DSM is, in some established markets, a market-arranged quantity that depends on both the offered price and the discretion of the LSE or load customer at the time such a price signal presents itself. The resultant amount of DSM that can actually be realized when needed is unpredictable.

This requirement also brings up a broader issue. Requirement 2 generally applies to Planning Coordinator and Transmission Planner, there is no distinction made as to which sub-requirements apply to which entity. In some markets, the Transmission Planner is responsible for assessing future needs for transmission facility only. It does not have the authority to even suggest a corrective plan that involves generation improvement or DSM. The way R2 and its sub-requirements is written is more suited for an integrated planning process, which may not exist in some places/developed markets.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: We feel that having the requirement to retest the conditions which show a performance deficiency, but now with the proposed corrective measures, would suffice. To illustrate or require "how a study area should be determined" would be micro-managing, and the term "a study area" is not defined anywhere in the standard and is subject to different interpretation. For example, does it mean the physical area of study or does it mean the various areas in the study that need to be explored. We are therefore unable to offer any view as to "how a study area should be determined".

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☒
Comment: Yes, the distinction should be made as committed projects have a higher degree of certainty to be available for the period under study, whereas a proposed project is one that is supported by the assessment but the commitment to proceed is not yet secured. However, we do not see the need (a) to establish criteria for committed projects and proposed projects, and (b) to distinguish between the criteria between them. If the standard should require a TP to assess both scenarios - with and without proposed projects, then this should be clearly stipulated.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☒
Comment: We agree that committed projects should not be removed from the revised plan. But we question the need for this sub-requirement which calls for: "Revisions to the Corrective Action Plans are allowed over time but shall meet the performance requirements.." Committed projects are normally included in the planning studies for which the performance is assessed. Deficiency, if identified, will have a corrective plans developed. We do not understand the need to remove or revise the committed plan in this context.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to “raise the bar.” Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	We agree, since the loss of a bus is a single contingency. This is a criterion already adopted by the IESO and other members in the NPCC region, for which non-consequential loss of load is not permitted.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☒Do not agree.	The sequence of events is too general that under some condition, it contradicts with the loss of 2 circuits on the same tower for which non-consequential loss of load is permitted. If the sequence of events is specified such that the two transmission circuits that can be lost are unrelated, then non-consequential loss of load should generally not be allowed following system adjustments after the loss of the first transmission circuit.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☒Do not agree.	Similar reason as above. In this case, the first transmission may also remove a transformer from service if they are in the same protection zone. The next contingency can be the loss of the companion transformer, without a fault on the transformer itself but not on the transmission circuit. If the transmission circuit and the transformer are unrelated, then we would agree that non-consequential loss of load should not be allowed.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☒Do not agree.	Similar reason as above.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: Agree. In general, non-consequential loss of load should not be permitted for any single contingencies.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment: See reason stated for Q24, above.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	The loss of a generator is different from the loss of a transmission facility. The former usually does not result in changes to the system topology nor system operating limits. While loss of 2 generators may result in resource deficiency, the decision to shed load would only be made when operating reserve cannot be replenished after the first contingency, and when the second contingency would result in violation of any SOLs or IROLs or BAL standards for which adjustment cannot be made within the required time line.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	Same reason as above except in this case, the loss of a monopolar dc line could interrupt import. Again, it is a resource issue, not a transmission reliability issue.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission	☒Agree. ☐Do not agree.	Similar reason as above. In this case, while the second contingency is the loss of a transmission circuit, the first contingency (loss of a generator) has

[1] System adjustment can be manual or automatic

circuit		not changed the system topology. Hence, the system condition after having been adjusted following the first contingency should in essence be similar to the all transmission facilities in service condition for which the non-consequential loss of load performance for single contingencies is expected.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	Similar reason as above.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒
Comment: Whether or not interruption of firm transfers should be allowed is more a business arrangement issue than a transmission reliability issue. Usually, delivery over a DC line, either as an import or access to internal or external resources, is factored into the resource integration plan to support meeting demand and energy transfers. The commitment for firm transfers may be made on the reliance of this delivery. However, the contingent loss of any resources including import is assessed in determining the amount and terms of firm transfers to a third part. This is a business and resource allocation issue, not a transmission reliability issue.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☒
Comment: We agree that the performance requirements for steady state analysis differ from those for stability analysis, but not the contingency requirements. While the specification of, for example, a line to ground fault on a single facility does not mean much to a steady state analysis, and in fact the loss of a single facility is all that it matters, the system is subject to the same type of contingency regardless of the type of analysis to be performed and hence the same contingency needs to be tested in both steady-state and dynamic simulations.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☒
Comment: We agree that both plant stability and system stability have to be studied and that both must exhibit acceptable performance to deem a testing acceptable. The performance requirements for the two could be different, but not the contingency set that must be tested.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment: Consistent with our comments provided under Q31, while the performance requirements may be different, there should be no distinction made to the type of contingencies that need to be applied to steady state testing and stability testing. An entire generating station may be lost due to various possible reasons: lost of right of way of transmission lines emanating from the generating station; generic protective relaying problems which cause all relays to operate due to a common cause or common mode event.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: Dynamic testing should assess response of moving equipment including induction motor loads.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Automatic adjustments should include AVR, excitation system, stabilizer and governor, all of which have pre-determined settings. These adjustments should be allowed for any type of contingencies. Manual adjustments that should or can be made other than removal of the generating units from service could include manual switching of transmission and adjustment to Phase Angle Regulators for so long that these actions are documented as applicable operating procedures.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment: Generation rejection and runback are not uncommon to be employed as special protection systems (SPS) to achieve a stable state and/or reduce transmission loading to within pre-determined levels. SPSs, when employed, are designed to operate in order to meet performance requirements following specific contingencies or when specific system conditions are present. As such, when a contingency occurs or when the conditions should arise for which the SPS (in this case, generation runback) is designed to operate, such actions should be simulated.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Please see our response to Q36 for the rationale for allowing the runback scheme to operate. The conditions that need to be met in order to allow the scheme to operate depends specifically on what that SPS (runback scheme) is designed for. Some schemes are designed to operate upon detecting the opening of specific transmission lines, others are designed to operate upon detection of circuit loading reaching a particular threshold. There is no universal rule as to the conditions that must be met for a runback scheme to operate. The use of runback scheme is similar to using special operating procedure, such as cross tripping, operator instructions to open a circuit, etc. There might be design requirements to ensure the scheme meet certain performance criteria. However, these should be covered in the standards for special protection system. In TPL-001, the requirement would be to include simulation of the runback scheme operation only as the conditions that would prompt the scheme to operate occur, and a requirement to include SPS misoperation, i.e., failure to operate and operate when not initiated, as a contingency.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: SPS and RAS should be allowed for single contingencies. However, a more fundamental requirement is that the SPS (and RAS) should generally be regarded as a stop gap measure before planned transmission expansion or reinforcement becomes available. SPS should in general not be used as a substitute for transmission facilities.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Please see comments provided under Q38, above, regarding the use of SPS not as a substitute for transmission facilities. In addition, there should be requirements to simulate failure of SPS operation as a contingency in addition to the initiating single contingency. In cases where an SPS is intended to achieve acceptable stability performance which can affect interconnection reliability, the SPS should be classified as BES impactive and as such, redundancy may be required. When redundancy is provided, simulation of SPS failing to operate may be waived.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: As indicated in the comments provided under Q38 and Q39, the conditions to simulate operation of the RAS and SPS would depend on the conditions they are designed to protect. We do not believe such conditions can be generalized.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:

(1) Pertaining to Q1 to Q11: we do not see the need to define this many terms for this standard. Many of the terms are easily understood and have been used in transmission planning for years that the majority of planners in the industry know what they mean. For example: base case, extreme contingencies (these are in fact listed in the table),

planning assessment, planning event, etc. Furthermore, the terms plant stability and system stability are also well understood to mean "machine synchronism" and "system oscillation/damping".

Among the proposed definitions, only the following terms need to be defined to add clarity:

a. Consequential (and non-consequential) loss of load
b. Long-term vs near-term (suggest to change it to short-term) planning horizons

(2) We do not see the need to use the term RAS (Remedial Action Scheme). The term SPS (Special Protection System) is common used in the industry to generally mean any protection scheme that is designed to initiate actions to control flows, voltage, generation runback or high speed rejection, switching of shunt devices, cross-tripping in response to some pre-determined parameters such as loss of a circuit or some threshold voltage or line flow level. Introducing the term RAS would be confusing to suggest that they do not equate to or are not a part of the SPS.

(3) We interpret the requirement stipulated in R1.1.1 is intended to enable more accurate simulations of load response - both in steady state and dynamic analyses. However, we do not support having this level of granularity (eg: industrial, commercial, residential etc.) stipulated in a planning assessment standard as similar requirements already exist in several MOD standards that deal with forecasted load and modeling. We suggest the mix of load detailed requirements be addressed in the latter set of standards. Similarly, R1.2 is best addressed in the MOD standards. Specific to R1.2, we do not agree with the requirement to provide supporting rationale that include power factor data based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements. Load forecast data already provides projected mix of real and reactive demands and type of load.

(4) R1.4 and R2.1.3 require outages be considered in the planning process. We suggest the SDT clearly stipulate that only known planned long term outages (with a minimum duration to be defined) need to be considered. This suggests is made on the basis that:

- Only known outages should be modeled. The need to model unknown outages would render study scope to be too wide to manage
- Only planned outages should be modeled for the same reason.
- Only known planned outages > a certain period should be modeled since it would be unrealistic and unmanageable to model and propose planning solutions to system constraints that appear to last less than, say, 2 weeks. As a general practice, many planners apply a 4 week period as the minimum for inclusion in planning assessment.

Without narrowing the scope, planning assessment will be an enormous task and difficult to manage.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name: Brian F. Thumm		
Organization: ITC Holdings		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment: Firm obligations may possibly include obligations beyond "firm transactions" which most likely means grandfathered transactions and TSRs as you have written it. The planning base cases should have sufficient margins to cover uncertainties as well as "firm transactions". The ATCTDT has "drafts" in place which require that TRM and CBM be included in transmission planning studies for both the near-term and long-term planning horizons. While they are drafts at this stage, consideration should be given to including their requirements in your drafts.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment: Suggest a change in terminology to "direct".**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment: R3.4 implies that "extreme events" will be studied as per the table. The definition seems functionally correct as applied to the standard but somewhat confusing. The existing wording implies that a mitigation plan should be developed if studies show that "extreme events" might cause cascading. If the mitigation plan is a true requirement, saying it is not a planning event can be confusing. "Extreme events are more severe than Planning Events, have a low probability of occurrence and only require___?????______ in the event of cascade."**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.

Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment: May want to change the terminology as some may interpret this to mean load that is not important and can routinely be shed for any contingency. Suggest 'direct load loss' and 'indirect load loss'. Potential Definition: Load that is not intended to be lost for normal fault clearing or during mis-operation but could be lost either by design, such as under frequency relaying, SPS or backup breaker clearing, or thru manual operator action.**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☐Do not agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☐Do not agree.
Q11. **Comment: Adding a statement specifying that this is at least ??? number of months into the future may be prudent.**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☒ No ☐
Comment: The standard should provide a minimum number of sensitivity cases that should be developed and should include at least a higher load forecast (90/10 vs. 50/50) and a higher generator unavailiablity (LOLE - 1 in 10).

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☒ No ☐
Comment: "Modification of expected transfers" should include unexpected loopflow caused by 3rd parties where applicable. In addition to the obvious impacts on system margins, loopflows have been identified as a major reason that FTR feasibility is hard to predict.

Also, see answer to Q12 above.

Some level of flexibility for some of the stressed cases should be left to the individual Planning areas as they would know typical load/stresses seen by their systems that should be studied and solutions identified for problems.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐

Comment: Both peak and off-peak models have been historically used for stability analysis and should continue to be used. The need for additional sensitivity studies should be left to the discreton of the Transmission Planner.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: We believe that both near-term and long-term studies should include sensitivity studies. Near-term studies may produce either operating solutions and more limited transmission solutions. It is just as or more important in a standard like this one to also do sensitivity analysis for the 6-10 year and beyond period. This is necessary to provide the needed advance notice for long-lead time alternatives to problems which are uncovered. Focusing on the next 5 years limits alternatives that can be implemented.

In fact, it makes sense to perform more sensitivity analysis on the longer term as assumptions become less probable the further out into the future you get. If a problem is identified in one snapshot 10 years out it may be less relevant than if it shows up in several varying snapshots 10 years out into the future. The use of sensitivity studies for the 6-10+ year horizon will hopefully have the effect of minimizing the use of band-aid type approaches to identified problems.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: DSM alternatives should focus on existing contractual relationships only. DSM is an alternative to "capacity solutions" and you have to give weight to how well you can count on it during capacity emergencies. Will the load be there to cut? How certain are you (contractually) that the load will be shed voluntarily when called upon to do so?

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: Without further study once a "solution" has been proposed how can one be sure it will work and not create "other" issues? The area of study should be developed using good engineering judgment with input from any neighboring parties that might be impacted.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: All projects should naturally become committed projects at some point prior to the need date. The time frame should be dependant on the scale and voltage class of the project.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: We agree.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	Should also consider no or limited loss of load for facilities 100 kV and above.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	Should also consider no or limited loss of Non-consequential load for facilities 100 kV and above. This should be no loss for load levels where the TO would expect to perform system maintenance.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	Should also consider no or limited loss of non-consequential load for facilities 100 kV and above. No loss should be allowed for load levels at which the TO would plan to perform maintenance. Also system adjustment should consider time required for adjustment verses the ratings utilized.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	Should also consider no or limited loss of non-consequential load for facilities 100 kV and above. No loss should be allowed for load levels at which the TO would plan to perform maintenance. Also system adjustment should consider time required for adjust.ment verses the facility ratings utilized.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐

Comment: Loss of non-consequential load should not be permited, however this should also apply to other breakers across the system including bus tie breakers.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment: Should also consider no loss of non-consequential load for facilities 100 kV and above and this should also apply to other breakers across the system including bus tie breakers.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	Also use of system adjustment should consider time required to complete adjustment.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	Also use of system adjustment should consider time required to complete adjustment.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	Also use of system adjustment should consider time required to complete adjustment. Ability for generation adjustment should include the time required for unit startup if applicable.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	Also use of system adjustment should consider time required to complete adjustment. Ability for generation adjustment should include the time required for unit startup if applicable.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐

[1] System adjustment can be manual or automatic

Comment: However, the owners of the firm transfers may not agree. If they don't, a system impact study needs to be part of the assessment IF THE OWNERS OF THE FIRM TRANSFERS DO NOT AGREE. It must be clear to the original TSR requester that this was truly conditional on the DC line being in service. If it was granted without telling them this, then the interruption of firm transfers should NOT be permitted.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment: We agree but consideration should be given to the amount of work needed by entities to meet these requirements. Full scale annual stability studies may not be needed. If possible, criteria should be developed as to when stability studies need to be repeated (if at all) and to what level (i.e. every bus on the system or just the generator busses or somewhere in between).

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment: See response to Q31.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: If it is not probable, then why study it. Realistic probabilities need to be established and defined for study.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: However this will require the Load Serving Entities provide specific data for each bus on the system which may not be in the direct control of the entity performing the studies. The standard should be written with this understanding in mind. Failure of a LSE to provide such data should not cause a penalty to be imposed on a Transmission Provider.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: There should be no change in generation for single contingencies. An approved SPS in those areas that use them might be an exception however system damage for failure to operate should not be allowed beyond the station with the SPS. Also, loss of load should not be allowed for failure to operate. An automated adjustment for multiple contingencies is not unrealistic.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☒
Comment: We believe that the BES should be able to operate for N-1 events without reliance on operating schemes. Assuming that some areas allow this, there should be criteria to evaluate the consequences of 2nd contingencies occurring during the runback. In addition, short-time ratings need to be confirmed which limit the time for runback. The system is at risk until the runback is completed and this risk must be evaluated and REQUIRED in the planning assessment.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☒
Comment: We wouldn't agree to this without knowing what you mean by limited use. RAS or SPS as a common practice does not "raise the bar" in planning standard. An RAS or SPS should be allowable as a temporary measure to allow one to meet the standard and two to protect the components of the BES. When used in this capacity, a plan should be being either developed or implemented such that the RAS or SPS can be removed from service.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Temporary in nature.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: This should be limited to the time until a physical solution is possible (i.e., a temporary solution).

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment: Variances should not be a reason to change the standard (lower the bar).

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: A modeling issue that we would like to see standardized is the modeling of generation resources when the load exceeds or is very near the installed reserve level (low generation reserve margin). This would occur in future years when new resources are unknown or not announced yet. It is a concern of ours because we are an independent transmission company and are not always apprised of new resources. We also have a concern with some models which "assume" where new generation would be located or fake generation has been added to meet the load requirements. This can produce distorted transmission assessments because the generation location assumption is not firm. We would prefer to see generation scaling, or an assumption that the power

will be imported or a combination of scaling and imports. Assuming 100% generator availability is also not a good assumption just to balance load and generation.

Other modeling issues:

1. Should not rely on a single generator being dispatched (redispatched) to solve a problem.

2. Using a single generator for redispatch should not be an acceptable corrective action (i.e. rely on a generator that might not be there or may take an extended period to start up).

3. Sensitivities for both the planning horizons should consider load forecast error and variability. You shouldn't just stick with one assumption, such as a 50/50 probability of occurrence. The system needs to be able to operate to loads exceeding 50/50 probability of occurance.

We would also like to see additional requirements be put on "corrective action" solutions to reliability violations resulting from planning assessments. Any corrective action should be restudied to insure that it does not cause other reliability problems for system conditions other than those for which the corrective action is intended to resolve. For example, if redispatch under a transmission outage condition is acceptable, it should not cause any additional reliability violations for the next contingency.

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Don Gilbert	
Organization:	JEA	
Telephone:	904-665-7109	
E-mail:	gilbdc@jea.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☒ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☐Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☐Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii “Sensitivity studies and critical system conditions” FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.

- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: Transmission Planners when developing system improvement options should identify their system specific sensitivity cases that best assesses the robustness of the options under consideration. Project evaluation is not addressed in the NERC standards and performing sensitivity assessments that only lead to operational remedies consistent with the standards, are best performed within the operational horizon where information and assumptions are more certain than within the planning horizon.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: Transmission Planners when developing system improvement options should identify their system specific "reasonable stressed" cases including opportunities for additional economic margins that best assesses the economic benefits of the options under consideration. Project evaluation is not addressed in the NERC standards and performing assessments on "reasonable stressed" cases that only lead to operational remedies consistent with the standards, are best performed within the operational horizon where information and assumptions are more certain than within the planning horizon.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐

Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☐
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☐
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐

Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	I do agree that long term plans should be implemented with the goal to eliminate non-consequential load shedding as a response to this failure mode. However, it may be more beneficial for investing in system improvements to reach this state of robustness where there may be a few years or seasons of potential exposure for utilizing non-consequential load shedding. This should be prudent utility practice as long as post-contingency response is executed within the time frame allowed by the facility emergency ratings and load shedding is limited to TP's contracted or tarrif loads.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	See comment on P4-3

[1] System adjustment can be manual or automatic

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:
In reference to the use of Non-consequential load shedding under single contingency events: I do agree that long term plans should be implemented with the goal to eliminate non-consequential load shedding as a response to this failure mode. However, it may be more beneficial for investing in system improvements to reach this state of robustness where there may be a few years (or seasons) of potential exposure for utilizing non-consequential load shedding. This should be prudent utility practice as long as post-contingency response is executed within the time frame allowed by the facility emergency ratings and load shedding is limited to Transmission Provider's contracted or tarrif loads.

For example, adding or upgrading transmission facilities into a load area where future generation additions are planned to be in-service within the short term horizon (mitigating thermal or voltage violations assessed under P1 and P4-1 through P4-4) would not be the best investment for the overall economic benefit of the bulk electric system.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Harold G. Wyble	
Organization:	Kansas City Power and Light	
Telephone:	816-654-1213	
E-mail:	harold.wyble@kcpl.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ ERCOT	☒	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs and ISOs
☐ MRO	☐	3 — Load-serving Entities
☐ NPCC	☐	4 — Transmission-dependent Utilities
☐ RFC	☐	5 — Electric Generators
☐ SERC	☐	6 — Electricity Brokers, Aggregators, and Marketers
☒ SPP	☐	7 — Large Electricity End Users
☐ WECC	☐	8 — Small Electricity End Users
☐ NA – Not Applicable	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment: Suggest changing "low" to "lower".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☒Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment: Suggest adding "Bulk Electric" before "System".**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment: Suggest adding "Bulk Electric" before "System".**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.

- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: N-1 and N-2 analyses should identify any additional sensitivity cases that need to be studied. This standard should not specify the number and type of sensitivities to be studied.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: Transmission Planner has best knowledge of conditions that create greatest stress on local transmission system.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒

Comment: Dynamic studies should be performed when new generation or transformers are added to the system. Should be performed on a periodic basis, not annually.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: Long term planning horizon has significantly greater uncertainty in future conditions and sensitivity studies are unlikely to contribute to reliability because of this.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in

conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: Only for DSM that is contractually "firm" and which can demonstrate mitigation performance (comparable to generation resource) as related to the transmission system.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: Corrective Action Plans taken by a transmission operator should not burden any of its' directly interconnected transmission operators. Study area should include at least all transmission operators directly interconnected to the transmission operator who took the initial corrective action. It may be appropriate to use the entire RTO/ISO/RRO as study area.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: Corrective Action Plans must demonstrate performance based on the expected system configuration. Committed projects can be changed or discontinued before completion.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to “raise the bar.” Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: No Non-Consequential loss of load for N-1 event.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment: Must recognize that there may be Consequential loss of load.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	Need voltage limit in Table 1.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐

[1] System adjustment can be manual or automatic

Comment: "Firm" capacity dependent on DC line is similar reliability as a generator.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Agree it is difficult to develop scenario where all units trip simultaneously in stability timeframe.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: Transmission operators are required to maintain reactive reserve requirements.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Generation redispatch should not be allowed for N-1 events. Generation redispatch is appropriate for multiple contingencies. Appropriate SPS and generation runback schemes should be allowed, where the system is designed with those schemes.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☒

Comment: All generators must have "firm" transmission outlet capacity for their nameplate rating. This means delivery of full output under N-1 conditions. A generator that must reduce output for N-1 is not "firm" generation capacity.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☒

Comment: All generators must have "firm" transmission outlet capacity.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☒

Comment: Tripping generation for single contingency other than GSU failure or fault is unacceptable.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: RAS/SPS should not limit generation output for N-1 conditions.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: RAS/SPS should not limit generation output for N-1 conditions.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☒ No ☐
Comment: In the past, Missouri Public Service Commission Staff have required KCPL to demonstrate that generators have "firm" transmission outlet capacity.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☐ No ☒
Comment: It is redundant to require provision of modeling data in this Standard. This is covered in Standards MOD 10, 12, 16-25.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Scotty Touchette	
Organization:	Lafayette Utilities System	
Telephone:	337-291-5994	
E-mail:	scotty@lus.org	

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☒ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☒Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.

- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☐
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☐
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☐
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☐
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to “raise the bar.” Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment:

[1] System adjustment can be manual or automatic

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment: The Planning Authority/Transmission Planner should use valid acceptable assessments to plan their systems to operate and supply customer demand and Firm Transmission Service. If the Planning Authority/Transmission Planner determines other methods (such as operational guides) to resolve system overloads for "N-1 Contingency", the operational guides should be limited to only native network facilities that are in direct control and ownership of the Planning Authority/Transmission Planner. Operational guides should be considered only as short term solution to resolve the overloads and shall be used in all studies and approval for transmission service requests. If the operational guide do not completely resolve the overload or restricts access to transmission service, then the Planning Authority/Transmission Planner shall determine facilities to be constructed to resolve the overloaded or restricted facility.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)	
Name:	Tim Wu
Organization:	LADWP
Telephone:	2133670650
E-mail:	chuan-hsier.wu@ladwp.com

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ ERCOT	☒	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs and ISOs
☐ MRO	☒	3 — Load-serving Entities
☐ NPCC	☐	4 — Transmission-dependent Utilities
☐ RFC	☒	5 — Electric Generators
☐ SERC	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ SPP	☐	7 — Large Electricity End Users
☒ WECC	☐	8 — Small Electricity End Users
☐ NA – Not Applicable	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: A basecase is a representation of the interconnected power system network at a given instant of time which correctly models an expected network topology in sufficient details (transmission lines, shunt and series compensations, transformers, breakers, phase-shifting transformers, etc.) , the forecasted loads, and a dispatch of connected generations that would achieve load-generation balance to allow a numerical solution without violation of any reliability standards. The resultant flows on the transmission lines are dictated by the Kirchhoff's laws, not laws of commerce, and therefore, cannot be interpreted as either firm or non-firm commercial transactions. A basecase is just a starting point from which transmission planners can make use of to further stress the portion of the systems that are of interests, to properly evaluate the robustness and reliability of the system and to determine line (non-thermal) ratings or network expansions, as needed.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: The existing standards does not allow load loss for N-1 contingency unless the load is a radial load of the outage element. This new definition appears an attempt to weaken the requirement by broadening it to anything "directly connected" to an element that is removed from service. While it may be argued that probably only radially connected loads fit this definition, this new definition will lead to more creative interpretation of the word "consequential" and leads all of us down unintended consequence. A radial load is a very specific and clearly defined technical term and should not be changed to a new term that is less precise.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree.

	☒Do not agree.
Q3. **Comment: Extreme events for transmission planning should be defined as anything more than N-2. The proposed definition is subjective and not precise. There are examples in this standard as to how this definition can be mis-construed, e.g., cyber attack, wild-fire, hurricanes, etc. These are extreme events that belong in emergency planning, not transmission planning.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☒Do not agree.
Q4. **Comment: The objection is not so much about the definition as about what comes after the definition. This standard proposed to include operating and market studies (calling them sensitivities) in the "nera-term" planning studies. It appears that the SDT believes this would be easier to justify if the sensitivities is limited to near-term and not long-term, hence the motivation for breaking the planning horizon. But this is mis-guided; operating studies belongs in operating standards. They should be addressed appropriately in the TOP for operating scenarios and Market related studies should be addressed in MOD, for example. There are no benefits to include these in transmission palnning studies and therefore no need to break up the planning horizon.**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☐Agree. ☒Do not agree.
Q5. **Comment: See my comment above; the only part about the definition that I would retain is to require each of the first five years in a typical ten-year plan be studied instead of just picking one or two years out of the first five years.**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: See my comment on the Consequential load loss. Why introduce two new and less precise definitions to replace one existing clearly defined definition? Radial load is precise and clearly defined to transmission planners.**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: The assessment of asset conditions and age of equipment belongs in maintenance practices, not a transmission planning issue. Similarly, Operating procedures is an operating matter, not planning studies. They have their own standards that could and should address any issue the SDT may have in mind. Using transmission planning as a catch-all is a wrong headed approach.**	

Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: The term Event has such a broad connotation that it can be misused by layperson. In fact, it is already misused in this standard as evidenced by including events such as cyber attacks, hurricans, tonados, etc as transmission planning events. These events belongs in "emergency" planning, not transmission planning.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: When performing transient stablity studies using either PSSE or PSLF, loss of synchronism and oscillation damping are automatically part of the performance evaluation; it is not a separate study and should not be classifed as a separate study. In the context of transmission planning, unless someone on the SDT use programs that do not have transient stability package similar to PSSE and PSLF, or has a completely different understanding on the meaning of loss of synchronism and/or damping, there is no need to introduce two new terms to explain a very well understood and established single term known as "transient stability" .**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: This comment should be taken together with the comment on Plant stability and I would recommend not to creat new terms and go back to use well established engineering terms like Transient Stability Study which covers synchronism, damping, voltage limits, angular stability, etc. There are many text books that could be used to support this.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment: very good clarification!**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: the FERC orders are market focused, not reliability focused; to the extent that these orders require sensitivity studies as outlined in this proposed standards, they belongs in operating studies and real time market studies, not transmission planning studies which are to meet reliability based criteria.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a “reasonably stressed” case?

Yes ☐ No ☒

Comment: A "reasnably stressed" case in transmission planning is whether or not the transmission system is stressed. To stress a transmission system, the key parameter to monitor are the line flows. Line flows are dictated by network topology and physics of electricity and very much depends on the objectives of each study, i.e., it is case by case. Standard should focus on what criteria shall be complied, not how to comply. This proposed standard is so prescriptive on how to comply that it reads like a tutorial.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒

Comment: This standard is mixing operational studies with planning studies. The suggested sensitivities in this proposed standards are what operating studies would and should address. It adds no value to the transmission planning by requiring sensitivities in transmission planning just for the sake of it. In addition, performing operating studies more than one year ahead, generally, is quite useless as a general requirement.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: This applies to both long- and near- term, the type of sensitivities proposed here do not belong in transmission planning studies.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒

Comment: We should be very careful about using DSM as Corrective Action for transmission problem. What this would lead to is to have a "built-in" transmission problem which would require DSM as the de facto rolling brown-outs or black-outs. DSM should be part of the resource and load forecasting consideration; transmission planning should design tranmission that can properly serve the forecasted loads with the expected resources; not to "live with" or include transmission contraints that rely on DSM as a solution. If the industry truly wants to use DSM as mitigation for transmission deficiencies, let's do it as a deliberate action, not an unintended consequence.

"System deficiencies" may be corrected with an integrated approach as suggested, but "transmission deficiencies" are solved by transmission improvement. The classic example is Path 15 in WSCC/WECC. The transmssion deficiency of PAth15 was well known for many years (like since '80s) and in the "pre-deregulated" dates, the deficiency was indeed managed by an integrated approach when the utility can operate its assets integrally. Then de-regulation happened and the integrated approach became unbundled and impossible resulted in numerous brown-outs and black-outs in California in 2000-01 until a third transmission line is added. Transmission deficiencies, if not mitigated, will significantly affect the accessibility to transmission services, a key concern of ferc 890.

As for new technology, just how the SDT proposes to define what constitutes a new technology? And how to measure for compliance against such a requirement? Hopefully, this is just another case of overly prescriptive standard.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒

Comment: This is a redundant and unnecessary requirement. How can one come up with a corrective action plan if it has not been demonstrated the plan can mitigate the problem? And if the corrective plan has been able to demonstrate that it can mitigate the problem, why repeat the study again.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: Seems like every company would have its own definition of committed vs propsoed project.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: All this does is create more bureaucratic tracking and paper pushing. People probably won't classify anything as committed until concrete has been poured just so not to have to deal with all these paperwork.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☐Do not agree.	There is a fundamental fatal flaw in having different reliability requirements using an arbitrary separation of the connected bulk electrical systems into above 300kV and below 300kV. The

		standard should be re-draft without this separation and comments be solicitated at that time. These questions are fundamentally unfair without first settling whether or not it is wise to arbitrary separate the bulk system into two different classes. This is like asking someone "Did you hit your spouse today?"
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☐Do not agree.	ditto
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	ditto
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	ditto

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: Don't understand why there is such an obsession with bus tie breakers? Is this a common practice in the East? I am not aware of any issue in WECC, let alone at above 300kV systems.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: ditto

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	This is N-2 and load loss should be permitted. As for whether or not this is a high probability event, there should be an objective measure (such as 1 in 5, 1 in 50, or 1 in 100, etc.) as to what constitute high probability, i.e., are there any outage history that would support any of the contention here that these are high probablity events? It is a mistake to arbitrary injecting "subjective" probability into a deterministic based reliability standard unless the industry is ready to move into 100% probabilistic based reliability standards.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	ditto
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	ditto
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	ditto

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

[1] System adjustment can be manual or automatic

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒

Comment: If the transfer is on a line experiencing outage, then the transfer is interrupted. Whether or not the transfer is firm is inmaterial. Whether or not it is on the dc or ac line is also inmaterial.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐

Comment: There is no vote needed here because even under the current standards, the performance requirements for steady state and stability are clearly separated. So what is being added?

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒

Comment: See my comment on the definition of Plant Stability. Unless the standard drafting team has something completely different from the common understanding of loss of synchronism and so on, transient stability covers both the so called Plant Stability and System Stability Studies.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment: Loss of a plant as an extreme contingency has been on the book forever and it has never been interpreted as exempted from stability simulation (at least not in WECC) if this secenario is chosen as an extreme event. However, there is no mandatory requirement that loss of all generating units at a plant must be studies for every generating plant. If the design of a generating plant, such as use of redundancy, separate control console/rooms, etc., are such that all unit tripping simultaneously is unlikely, then it should not be requried to be studied just because all the units are inside the fence.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐

Comment: This is a qualified yes to the extent that accurate induction motor models are available and the overall load modeling (non-induction motor loads) allow such analysis. Otherwise, focusing only on induction motors would not provide added information than what is being performed today. The current WECC requriement concerning induction motor modeling should be deemed adequate to meet this requirement.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Whatever is needed to bring the system into balance.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: Generator runback is allowed under the current standards, why single this out? Hopefully this is not a sign of equating generator runback with generator tripping as the title of this section might suggested. Generator runback is not and should not be classified as an SPS!

It is critical to keep as many units on line as possible post contingency. In many instances, use of generator runback would avoid the need to trip a unit if that was the only way to reduce the generations to return to load-generation balances.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐

Comment: It was never disallowed under the current standards.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☐
Comment: no comment

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: Too many to be listed with the separation above and below 300kV being the worst one that will undermine the overall reliability of the electric system in North America. Another major omission in this proposed standard is the complete lack of recognition of the importance of post-transient requirements. Mixing commercial (firm or non-firm transsactions, etc.) and reliability in transmission planning criteria would be in conflicts with WECC rules and practices.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: This proposed standard is very tutorial in nature and far too prescriptive for a standard. A standard should be about what are the criteria and measurables, not about how to meet the criteria.
This propsoed standard should also recognized that it is just a part of many standards being formulated by NERC, know its boundary as transmission planning standard, and not try to be an all encompassing standard for every facit of the power system. Do what we do best as transmission planner and not try to take over others like marketer, operator, generators, etc.

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Sergio Garza	
Organization:	LCRA TSC	
Telephone:	512-369-4149	
E-mail:	sergio.garza@lcra.org	

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☒ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☒	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment: Should read "Computer model representation of…"**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment: Define "low probability of occurrence"**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☐Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment: "Documented evaluation of future Bulk Electric System performance conducted through performance studies…"**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.

- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: There are two questions asked and the response is yes to both. In the ERCOT region, load flow cases are not currently availbale for years 6-10 and this limits the long-term study activity that Transmsion Owners and Transmission Planners can acarry out. As currently proposed (R2.2) is appropriate.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in

conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: The question is not clear regarding "study area"; however, re-testing with corrective action / system improvement(s) in place is a must. The re-test must consider the same simulations that idenitifed the initial deficiency.

In addition, in the re-test, the action/ system inprovement must be considered as a Planning Event itself (i.e., if the initial test showed a specific contingency causing a deficiency, then a physical connection of the system improvement to the identified continegncy should be avoided or minimized - minimize the creation of extreme events.). In other words, planning solutions should be long-term and a system "fix" for the present should not result in a system problem in the foreseeable future.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐

[1] System adjustment can be manual or automatic

Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☒
Comment: Only until plans are implemented to address a single continegcy-identified deficiency. In general, plans should always be developed to exit SPS or RAS when economically feasible

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Short-term with exit plans; Loss of significant generation or load resulting from SPS /RAS action

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: Systems must have a balance between security and dependabiliyt. System must be reviewed annually or as system conditions change.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: See ERCOT Planning Criteria. Also, through the regional coordinators, NERC recently conducted a survey of transmision planners/owners regarding use of more stringent criteria used in their own systems. The std. drafting team should include a review of the survey results and incorporate into this NERC std as necessary.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: The NERC PC and OC are currently working on a definiton that defines "adequate levels of reliability". The SDT should take this definition into consideration and ensure it is applied in the proposed NERC Std. revision. Along the same lines, if this has not been done yet, the SDT needs to consider the NERC "Reliability Criteria and Operating Limits Concepts" white paper and incorporate applicable elemetns of that white paper to the propsoed NERC Std. revision accordingly. It would not make sense for these (the propsoed NERC std. and the noted white paper to be inconsistent or at opposite ends in terms of what is expected of a reliability-based planned transmission system).

other editorial comments:
1. R1. Delete one of the "each"

2. R1. Should state that data submittals should be "in accordance with regional procedures or process". This will eliminate the region getting data in all sorts of formats.

3. Table 1 - the allowance of loosing "consequential load" should be evaluated based on options to provide temporary emergency back-up support as well as size of load, for example. Structure failures can take an extended period of time to restore and can have significant impacts on a raial load that does not have remote or distribution back-up support. This performance requirment of transmisssion radial-supplied loads should be left to regions or to transmission owners/planners for their own areas based on specific area needs (type and size of load, back-up availbailiyt, etc.).

4. Table 1 - How does NERC define a "transmission circuit"? Does it include a sinlge transmission line as well as a double circuit transmission line?

5. Other than the probability of occurrence, what is the difference between a structure failure of a single circuit and a structure failure on a double circuit configuration? Why is a double circuit not considered a single contingency?

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Ron Mazur	
Organization:	Manitoba Hydro	
Telephone:	204 474 3113	
E-mail:	rwmazur@hydro.mb.ca	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☒ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment: If load losses due to stuck breaker and back-up breaker operations (which would frequently result in the loss of two or more network transmission elements) are not going to be qualified as "Consequential", where should they be placed? MH cannot visualize them as "Non-Consequential", as defined in Q6. Either another "load" category must be developed for these loads, or they should remain as "Consequential". In addition, Consequential Load Loss should include the concept of local area load loss to cover a scenario of islanding with a UFLS in the island, or a small network served at the end of a radial line.Can the SDT comment on why this Local Area defined in the existing TPL stds has been removed?**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Change to "Events which are more severe than Planning Events and have a lower probability of occurrence than Planning Events."**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not

	agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☐Do not agree.
Q7. **Comment: A planning assessment should include performance studies.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: The definition of a planned event should relate to the probablity of occurance. Table shows single contingency planned events and multiple contingency planned events. Why has the SDT gone away from the existing categories of events which sorted the events into categories with different levels probability.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: The words "Bulk Electric" should be added before "System".**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: The words "Bulk Electric" should be added before both occurances of "System".**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii “Sensitivity studies and critical system conditions” FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: Sensitivity analysis that could be considered will vary from region to region or subregion to subregion.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☒ No ☐

Comment: R.2.1.3.2: clarify the intent of modification of expected transfers. Does this apply to firm transfers only, or does it also encompass non-firm transfers? Should this encompass simultaneous non-firm transfers? Planning for non-firm falls into an economic study of cost/benefit and not a relibility requirement.

R2.1.3.3: There is little value in identifying the impact of unavailability of planned facilities. From a reliability perspective, these facilities are required to meet performance requirements. Near term SOLs and IROLs will insure reliability if the facility is late.

R.2.1.3.4: This requirement should be removed and outages of reactive resources should be included in the Table 1 contingencies (assuming the intent is to investigate robustness to voltage instability).

R.2.1.3.5: This requirement should be removed as this is covered, or should be, by the facility connection standard(s).

R.2.1.3.6: This requirement should be removed as this is covered by requirement R2.1.3.1. There is no need to list "decreased effectiveness of controllable loads or DSM" as this is already covered by sensitivity to forecast load and power factor - this will cause confusion.

R.2.1.3.7: Modification of planned Transmission outages should be deleted. The need to assess outages in the planning horizon is questionable, so assessing sensitivity to timing of these outages is of very little value. Furthermore, this standard already covers prior outages in its other requirements.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐

Comment: R2.4.3.1: This requirement should include variation in load power factor, as this has a significant impact on transient performance.
R2.4.3.3: There is little value in identifying the impact of unavailability of planned facilities. From a reliability perspective, these facilities are required to meet performance requirements. Near term SOLs and IROLs will insure reliability if the facility is late.
R.2.4.3.4: This requirement should be removed and dispatch of reactive power devices should be included in the Table 2 contingencies (assuming the intent is to investigate robustness to voltage instability).
R.2.4.3.5: This requirement should be removed as this is covered, or should be, by the facility connection standard(s).

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: The models for Long-Term Transmission System Planning Horizon typically contain such uncertainty that the base planning is a sensitivity study itself. Sensitivity studies in these years would be a waste of time. The long term analysis should be used to indicate trends such as a reduction in transfer capability, reduction in damping, etc, but not necessarily seek mitigation of such trends.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒

Comment: DSM and generation improvements should be removed from Requirement R2.7.1, as they should not be mandated by a NERC standard are not in the tool box of the transmission planner.
DSM may already be in the load forecast and sensitivities to load forecast variations are included in near term planning horizon sensitivity analysis. Additional DSM shouldn't be part of transmission planners mitigation

plan. If the corrective plan is too expensive the load serving entity could consider DSM and revise their forecast in the next planning cycle.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐

Comment: At some point the corrective action plan should be tested to verify the plan meets the performance requirements. The way the standard is written is that the transmission plan should be perfect for the entire planning horizon for all sensitivities tested. Any issues should be immediately addressed. The standard does not allow any time to develop a corrective plan through an open and transparent process. Based on the NERC definition, a Corrective Action Plan is the list of actions and an associated timetable for implementation to remedy a specific problem. A Corrective Action Plan could mean that load forecasts at the station will be verified, facility ratings verified and alternatives to fix the identified problem to be determined before the next Planning Assessment. Standard R2.7 seems to be mixing the idea of a Corrective Action Plan with the original TPL idea of determining corrective plans to achieve required performance. A corrective plan wil be the end goal of a Corrective Action Plan.
Furthermore, corrective action plans should not be requierd to address issues raised by sensitivity studies. Corrective action plans are developed to meet base case needs which are based on expected load forecasts, transfers, etc. Sensitivity studies are done to measure the robustness of the base case plan. It should be left up to the Planner to decide if the corrective action plan is adequate based on the likelihood of the scenario studied, even if the sensitivity analysis shows some performance violations.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐

Comment: However, since each planner is allowed to define the criteria, there will be no consistency as to what is included in the base case models.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒

Comment: The standard does not allow any time to develop a corrective plan through an open and transparent process. Based on the NERC definition, a Corrective Action Plan is the list of actions and an associated timetable for implementation to remedy a specific problem. A Corrective Action Plan could mean that load forecasts at the station will be verified, facility ratings verified and alternatives to fix the identified problem to be determined before the next Planning Assessment. This standard seems to be mixing the idea of a Corrective Action Plan with the original TPL idea of determining corrective plans to achieve required performance. A corrective plan wil be the end goal of a Corrective Action Plan.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-

0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	With the caveat that if the loss of load is localized, it is acceptable. Raising the bar will result in a cost increase for owners and users of the transmission system. What evidence does the SDT have to show this is justified.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed	☒Agree. ☐Do not agree.	

by System adjustment followed by loss of another transformer		

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐
Comment: Until the SDT should defines a non-bus tie breaker this is impossible to answer.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: The SDT seems fixated on loss of load. The existing std for this type of event allowed for loss of load and firm transfer could be adjusted. While MH could rationalize that load should not be interrupted, we could not agree that firm transfer can not be reduced. This would amount to n-2 planning to maintain a firm transfer that is backed up by reserves. The requirement to maintain firm transfer will cost MH and the industry millions of dollars with no reliability benefit - a show stopper.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	With the caveat that firm transfer is included in the adjustment, otherwise there is a hugh cost with minimal reliability benefit. A further comment is what rationale was applied by the SDT to come up with these combinations of events? is there a statistical basis? the vible combinations of multiple contigency events should be left to the experience of the transmission planner.
Q27. P4-2: Loss of a generator followed by a	☒Agree.	With the caveat that firm transfer is included in the adjustment, otherwise

[1] System adjustment can be manual or automatic

System adjustment followed by the loss of a monopolar DC line	☐Do not agree.	there is a hugh cost with minimal reliability benefit.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	With the caveat that firm transfer is included in the adjustment, otherwise there is a hugh cost with minimal reliability benefit.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	With the caveat that firm transfer is included in the adjustment, otherwise there is a hugh cost with minimal reliability benefit.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐

Comment: MH agrees that reduction of firm transfer to readjust the system after a contingency should be allowed for all events. The requirement to maintain firm transfer is a more stringent requirement that in the existing standard. The need to maintain firm transfer amounts to N-2 planning with no reliability benefit. Reduction in firm transfer is not equivalent to loss of load as the transfer is backed up by reserves. MH could not accept a standard mandating that firm transfer can not be interrupted.

MH also recommends P2-3 be moved into the P1 bucket as loss of a single pole of a dc line is similar to loss of a generator or transmission circuit.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐

Comment: Yes but the definition of contingencies in table 1 and table 2 should be identical

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒

Comment: The need to assess Plant Stability should be removed from this standard. The generator connection standard and the proforma tariff interconnection process ensure the plant stability meets performance requirements. Furthermore, the System Assessment provides an overall assessment of the integrated system performance, which includes the impact of the plant. The requirement for plant stability studies appears to be redundant and would be a waste of assessment resources.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment: Isn't 2.d such an event? In a breaker-and-1/3 or 1/2 generating station, if one station bus is off-line for maintenance, faulting the other bus will kill the station, or at least cause a major disruption with individual generators connected to other stations by separated lines. That is certainly worthy of consideration as a feasible "extreme" event Further, the same low likeihood argument could be applied for the majority of extreme events in Table 2.The emphasis should be on what the response is for extreme events rather than the likelihood of the event. .

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: R2.4.1 should be clarified to limit a requirement for detailed modeling (for example, dynamic effects of induction motors loads) to local areas where the planner expects a local emerging voltage recovery issue.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: 1) Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation change should be limited to that amount that can be accomplished within the allowed readjustment period. Due consideration should be given to start up time and ramp rates of the units.
2) Generator tripping should be added to requirement R3.5 in addition to runback. Generator tripping is used extensively in regions where remote generation is delivered via long transmission.
3) Adjustment of firm transfer must be allowed for single and multiple contingency events. MH could not accept the revised standard that removed this existing requirement.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency

outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: Generator tripping should be added in addition to runback. Generator tripping is used extensively in regions where remote generation is delivered via long transmission There will be a large cost penalty to construct transmisison to remote generation if generator tripping is not allowed. Since the amount of tripping is covered by operating eserves, there is no impact on reliability. Generator tripping should be an option for the planner in the standard as opposed to a regional difference or the need to install an SPS. .

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐

Comment: I see no problem in using a runback scheme to prevent thermal overloads. Most emergency ratings are based on 30 minute values to allow for operator action. An automatic runback could be accomplished in 5-15 minutes depending on the ramp rate of the generator. The runback scheme may allow higher emergency ratings depending on the rating methodology. At no point would emergency ratings be exceeded and at the end, loading would be within normal values.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐

Comment: MH sees no reason to limit the application of SPSs. The SPS is a viable planning option that allows large savings in cost in stability limited system where there is no need to increase thermal capability.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: An automatic runback should be accomplished in 5-15 minutes depending on the ramp rate of the generator. The runback scheme may allow higher emergency ratings depending on the rating methodology. At no point would emergency ratings be exceeded and at the end, loading would be within normal values. Generator tripping should be allowed. Generator tripping is used extensively in regions where remote generation is delivered via long transmission. MH sees no reason to limit the application of SPSs. The SPS is a viable planning option that allows large savings in cost in stability limited system where there is no need to increase thermal capability. .

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: 1) Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation change should be limited to that amount that can be accomplished within the allowed readjustment period. Due consideration should be given to start up time and ramp rates of the units.
2) Generator tripping should be added to requirement R3.5 in addition to runback. Generator tripping is used extensively in regions where remote generation is delivered via long transmission.
3) Capacitor and reactor switching - The number of capacitors and reactors, which may be switched, should be limited to those which could be switched during the allowed readjustment period.
4) Adjustment of load tap changers (LTCs) to the extent possible within the allowed readjustment period.
5) Adjustment of phase shifters to the extent possible within the allowed readjustment period.
6) An increase or decrease to the flow on HVDC facilities to the extent possible within the allowed readjustment period.
7) Transmission reconfiguration - Automatic tripping of transmission lines or transformers to the extent possible within the allowed readjustment period.
8) Automatic tripping of interruptible load or curtailment of or redispatching of Firm Transmission Service to the extent possible within the allowed readjustment period.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☒
Comment: MH does not like the idea of a long transition period. Either NERC adopts the concept of generation rejection or the MRO will need to submit a regional variation. I much prefer the planned loss of generation via an SPS rather than via out-of-step tripping as proposed in the Table 2. In certain areas of the MRO that are stability limited because of long lines to bring generation at the energy source (such as mine mouth plants, hydro plants, etc.) to the load, generation rejection is used to return from an emergency state to a normal state. If generation rejection is not allowed in these cases, extraordinary cost and extraordinary negative environmental impacts will result. As an example, removing one SPS will require new 500 kV transmission between Winnipeg and Minneapolis at a cost of $1 billion to MRO utilities.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: MH would prefer that many of the categories in the existing Table 1 be retained. The SDT has resort the contingency buckets with no explanation as to how this was done. can the SDT provide statistical outage date to justify the changes. MH is not convinced the SDT has addressed the few confusioning issues in Table 1.

R1: MH does not believe R1 is required in this standard. The modelling standards should cover the requirement of the data owners to provide data to the PC.
Further this data needs to be provided to the TP as well.

R1.4: requires planned outage data to be provided to planners. I do not believe this is a requirement for planning. It is not economic to add facilities to accommodate future planned outages. Secondly, the Table 1 multiple contingencies already mandate that planners consider the impacts of an outage with system adjustment followed by testing for the next contingency.

R1.5: requires the PC to define "planned facilities" which should be included in the model. This will lead to inconsistency in what is modelled, as experience has shown that there will be a wide range of assumptions in the definition. This standard should offer a definition for stakeholder debate. The SDT should clarify what is intended by including Protection System Equipment and control devices.

R2.1: It is not necessary to assess all five years of the near term planning horizon – year one, three and five will be more than sufficient. What is the reliability benefit driving the SDT to mandate each of the first five years be assessed?

R2.1.2 and R2.4.2 -- It is important to assess off peak loads with high simultaneous transfers as this is the period where extensive economic interchange occurs, and transient stability issues arise as less uneconomic peak units are off, leaving the load to be supplied by remote generation with reduced local reactive supply, voltage and damping control.

R2.2: The long term assessment should also include an off peak case with simultaneous transfers to provide some indication if the system performance is expected to degrade.

R2.3: The short circuit study is a design issue that would more appropriately covered by a FAC standard. MH recommends it be removed from the Planning standard.

R2.6.1: Why would a past study be invalidated if there is a change in market structure? It would seem that the operation of any market would have to respect reliability criteria.

R.3.3.2.2: Curtailment of firm transfers is allowed as a system adjustment in the existing standard. This ability must be retained in the new standard. Curtailment of a firm transaction is not equivalent to curtailment of load, but is more comparable to runback/tripping of generators. Both are events that can be backed up by contingency reserves and do not result in consequential load loss. Disallowing firm transfer curtailment will result in numerous violations of the performance requirements and result in a requirement to build millions of dollars of transmission. MH can not accept a standard which mandates that firm transfers can not be curtialed following a contingency.

R3.3.3: If rationale for the contingencies selected for evaluation is available then this rationale will state why the selected contingencies are expected to be the most severe. The requirement does not need to state "and shall include an explanation of why the remaining Contingencies would produce less severe System resuts".This is redundant.

R3.4 and R4.5.2: Evaluating a change designed to mitigate the consequences of an exteme event can require significant work. Since there is no requirement to implement corrective plans for extreme events, what is the purpose of this evaluation?

R3.5: Generator tripping should be added in addition to runback. Generator tripping is used extensively in regions where remote generation is delivered via long transmission.

R6: Requires distribution of results and "coordinating analysis of these results through an open and transparent process". Can the SDT clarify what the intent is? As written, it implies the PC/TP just shares assessment results with neighbours. There should be a requirement to conduct joint assessments on inter-regional transfer capability.
The assessments should also be provided to the Regional Entities/NERC.

Table 1 -Steady State Performance

MH requests the SDT to provide rationale for how the planning events where resorted from the existing Table 1 Categories to the proposed Planned events.

Performance Requirements: As this is a steady state table, how does one assess if voltage instability, cascading outages or islanding occurs? "Simulate Normal Clearing unless otherwise specified." should be deleted from this Steady State Performance table.

This table should have an Initial Condition column as well as an Event column, as in Table 2. The wording of event descriptions in Table 1 should follow the wording of similar event descriptions in Table 2.

Event: What is a non-bus tie breaker? Is this any breaker that is not a bus tie breaker?

Interruption of Firm Transfer Allowed: Interruption of firm transfer should be allowed following a single contingency – this is a change from the existing standard where system adjustment after a Cat B event could include reduction of firm transfer. Similar to generation tripping/runback, the loss of a firm transaction does not result in Consequential load loss as it is backed up by contingency reserve.

P6-2: What is the justification for classifing a bipolar DC line loss as a single contingency? The existing standard classifies this event as a Cat C multiple contingency event.

P6-3: Why is a breaker internal fault classified as a single contingency? One would assume such a fault would be cleared by backup protection resulting in the loss of multiple elements.

P9-1: Is there any justification for the selection of one mile? Would the fact that there is line shielding be justification for increasing this length? A more reasonable selection could be 5% of the length of the longer of the two circuits.

P9-2: A monopolar DC line loss may be covered in P4-2 (and no non-consequential load loss is allowed). Does loss of a monopolar DC line refer to loss of a single pole of a bipolar line or a bipolar dc line? Can the PC/TP choose between the loss of a monopolar DC line and the loss of a bipolar DC line?

P9-3, P9-4 and P9-5: When the DC line loss is bipolar, the event should be moved to the extreme event category. Does loss of a monopolar DC line refer to loss of a single pole of a bipolar line or a bipolar dc line? Can the PC/TP choose between the loss of a monopolar DC line and the loss of a bipolar DC line?

Exteme Events Evaluation Requirements 3: This should be removed as this is the Steady State Performance table.

Extreme Event Descriptions: How did the SDT determine what events should be classified as extreme events? Was statistical data analyzed?

Extreme Event 1: In the existing TPL standards, the simultaneous loss of two elements was considered a Cat C multiple element event. What is the SDT rational for the change?

Extreme Event 2c: Why is the loss of a single large load an Extreme Event?

Extreme Event 3f: This is a repeat of Extreme Event 3d.

Extreme Event 3g: What is the rationale for distinguishing between old vs. new design for the loss of multiple lines due to icing? Is the SDT implying that new lines must be desined to prevent multiple line loss due to icing?

Table 2 - Stability Performance Table

Performance Requirements: The MRO adds 1/2 to 1 cycle to the Normal Clearing time during simluations as an additional safety margin. The SDT should consider enforcing this practice.

Event: What is a non-bus tie breaker? Is this any breaker that is not a bus tie breaker?

P1: There should be a P1-4 event for a shunt device (ie. "4. A shunt device (including FACTS devices)").

P6-2: What is the justification for classifing a bipolar DC line loss as a single contingency? The existing standard classifies this event as a Cat C multiple contingency event.

P6-3: Why is a breaker internal fault classified as a single contingency? One would assume such a fault would be cleared by backup protection resulting in the loss of multiple elements.

P9-1: Is there any justification for the selection of one mile? Would the fact that there is line shielding be justification for increasing this length? A more reasonable selection could be 5% of the length of the longer of the two circuits.

P9-3: This contingency should be classified as an Extreme Event since statistically, the outage duration of a dc circuit (assume you mean a bipole) is less than 2 hours for MH bipoles, so the probability of a second outage is very low. .

P9-6: Isn't this the same as P1-3? If the outaged tranformer is replaced by a spare transformer, this restores the system to a normal state prior to the event ("Apply a P1.3 Contingency."). What is the point?

Note 1.a.i.: Planning Event P3.2 does not exist.

Note 1.a.ii: This definition of angular stability should be deleted and the definition in Note 1.a.i. should apply to all Planning Events. The system should not be considered to be angular stable when generators are pulling out of synchronism.

Note 1.a.iii.: This standard should define a minimum damping factor and allow the PC/TP to have a more restrictive damping requirement if they choose to.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Jerry Tang	
Organization:	Municipal Electric Authority of Georgia	
Telephone:	770-563-8190	
E-mail:	jtang@meagpower.org	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment: MEAG believes that deleting the term "mis-operation" as some may have suggested, would significantly narrow the definition of Consequential Load Loss, which in turn would unreasonably increase the amount of load that is Non-Consequential. The Non-consequestial load loss, which is not allowed in P1-P5. For example, if mis-operation is deleted from the definition and we consider a relay mis-operation where a breaker fails to clear a fault, then any additional load interrupted by the back-up to the failed breaker/relay is Non-Consequential Load (and the standard appears to be violated since only a single transmission circuit was faulted and Non-Consequential Load was lost).**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: A number of the non-extreme events also have a low probability. Recommend change the word to "lower." The definition for "Extreme Events" should reference Table 1.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not

	agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Bulk Electric System deficiencies rather than needs should be evaluated. We do not agree that the planning assessment should include asset conditions and age. This is a preventive maintenace issue. The age of equipment, if it is well maintained, has little impact on reliability.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Change to: "Events that are simulated or assessed to test the transmission system to ensure that performance requirements are met."**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment: Change " the System" to "local area of the Bulk Electric System." It also need a definition for "plant."**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment: Change "System or portions of the system" to "Bulk Electric System's components associated with the Transmission Planer."**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment: The last sentence in the above definition was not included in the definition listed in the draft standard, nor should it be.**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The entity performing the studies should be allowed to determine the appropriate number of cases that need to be evaluated. Different utilities have different input assumptions, therefore the selection of sensitivities to study are different. For example, some utility needs to study the water availability for its hydro units, while other utility needs to evalauate the sensitivity of gas availability.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The standard may offer guidance but what constitutes a "reasonably stressed" case will vary from Transmission Planner to Transmission Planner. Therefore, it should be left to the discretion of the entity performing the study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐

Comment: The entity performing the studies should be allowed to determine the appropriate sensitivity studies that need to be evaluated. An alternate approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency. Stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: We concur with the current approach.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: DSM should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is available for curtailment by the System Operator and without the option to buy through and remain in service.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: Re-testing should be required only where the correction may impact network flows. The study area should be determined by the TP. The TP has the most knowledge of how the system responds to changes and should be allowed to choose the study area based on the prudent utility practice.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: The goal is to meet the system performance requirements outlined in the standard. Whether a project is proposed or committed is not relevant.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒

Comment: See response to Q18.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	see Q20 above.
Q22. P5-2: For facilities above 300 kV, loss of a	☐Agree.	see Q20 above.

Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	see Q20 above.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: See response to Q20.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: See response to Q20.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed	☐Agree. ☐Do not agree.	

[1] System adjustment can be manual or automatic

by the loss of a monopolar DC line		
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment: Generator protection is designed to trip only those units required. In addition, it is the magnitude of generation tripped rather than the number of units tripped that is of the greatest significance to the stability of the grid.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒

Comment: Dynamic studies of seasonal load conditions should include the effects of induction motors, and particularly in areas where traditional load models have indicated a problem. Unfortunately, there is a lack of data to support the amount and characteristics of the detailed induction load models in many areas. In addition to the consideration of the dynamic effects of induction motor loads, the effects of static capacitor banks installed at distribution voltage levels would need to be considered as well. Prior to making this a requirement in the reliability standards, the industry needs guidance as to how this data should be developed and maintained for models in future years.

Note that meeting such a requirement would necessitate a significant increase in the dynamic data needed to represent the system. Maintenance of such load model data would require significant resources. Load characteristics valid for a near term model might not be valid for future years. Also, summer peak load, winter peak load, and off-peak load characteristics would differ.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Adjustments that should be allowed are those that can be performed in time to prevent the system from failing to meet performance requirements. These adjustments may include automatic voltage regulator action, governor action, generator runback, and generator tripping.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: The generator runback scheme should complete its action within the time allowed by the emergency ratings of elements that exceed their normal thermal ratings.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: RAS or SPS should meet the same criteria as any protection system.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: The conditions required by SPS standards (PRC).

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: Facilities rating methodology are different from region to region and company to company.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment: To the extent that the new standard is more stringent, additional time should be allowed to implement the corrective action plan, with fines suspended until reasonable time has passed to allow implementation. I.E., If the solution is 20 miles of new 500 kV T/L, then allowing fines to the short-term horizon is unreasonable – building 20 miles of 500 kV T/L is not possible in 2 or 3 years.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

<table>
<tr><th colspan="3">Individual Commenter Information
(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td colspan="3">Name:</td></tr>
<tr><td colspan="3">Organization:</td></tr>
<tr><td colspan="3">Telephone:</td></tr>
<tr><td colspan="3">E-mail:</td></tr>
<tr><td>NERC Region (check all Regions in which your company operates)</td><td></td><td>Registered Ballot Body Segment (check all industry segments in which your company is registered)</td></tr>
<tr><td rowspan="10">☐ ERCOT
☐ FRCC
☒ MRO
☐ NPCC
☒ RFC
☒ SERC
☐ SPP
☐ WECC
☐ NA – Not Applicable</td><td>☐</td><td>1 — Transmission Owners</td></tr>
<tr><td>☒</td><td>2 — RTOs and ISOs</td></tr>
<tr><td>☐</td><td>3 — Load-serving Entities</td></tr>
<tr><td>☐</td><td>4 — Transmission-dependent Utilities</td></tr>
<tr><td>☐</td><td>5 — Electric Generators</td></tr>
<tr><td>☐</td><td>6 — Electricity Brokers, Aggregators, and Marketers</td></tr>
<tr><td>☐</td><td>7 — Large Electricity End Users</td></tr>
<tr><td>☐</td><td>8 — Small Electricity End Users</td></tr>
<tr><td>☐</td><td>9 — Federal, State, Provincial Regulatory or other Government Entities</td></tr>
<tr><td>☐</td><td>10 — Regional Reliability Organizations and Regional Entities</td></tr>
</table>

Group Comments (Complete this page if comments are from a group.)

Group Name: **Midwest ISO, Inc.**

Lead Contact: **Allen McKee**

Contact Organization: **Midwest ISO, Inc.**

Contact Segment: **RTOs and ISOs**

Contact Telephone: **(317) 249-5220**

Contact E-mail: **amckee@midwestiso.org**

Additional Member Name	Additional Member Organization	Region*	Segment*
Karl Kohlrus	City Water, Light & Power-Springfield, Illinois	**SERC**	5
Jim Cyrulewski, P.E.	JDRJC Associates	RFC	8
Joseph DePoorter	Madison Gas & Electric	MRO	4

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the

rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: Midwest ISO suggests this definition be changed to "Direct Load Loss", as "Consequential Load Loss" may include elements that are not directly connected to the faulted element.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Extreme Events are clearly described on Table 1. Change definition from "low probability of occurrence to "lower probability of occurrence".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs	☐Agree.

through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Do not agree.
Q6. **Comment: Midwest ISO suggests this definition be changed to "Indirect Load Loss", as "Non-Consequential Load Loss" may be confusing regarding the cause-and-effect relationship between a faulted element and subsequent loss of load.**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☐Do not agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: The words "Bulk Electric" should be added before "System".**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: The words "Bulk Electric" should be added before both occurences of "System".**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the

requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: Requirements 2.1.3 and 2.4.3 call for sensitivity cases that stress the system, with documentation as to the rationale for why a particular sensitivity was selected. Midwest ISO believes that the standard must balance clarity and specificity with flexibility and discretion. If the standard is too prescriptive in the system conditions to be evaluated, sensitivity studies that reflect critical system conditions that experience dictates are appropriate for a given system could be construed as being outside of the standards. Such a determination could make the regulatory approvals of facilties needed for reliability purposes difficult or impossible to obtain. Midwest ISO believes hat the language in the existing standard TPL-001-0, R1.3.2, which states that "PA and TP assessments shall cover critical system conditions and study years as deemed appropriate by the responsible entity" provides the proper balance of these issues.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a “reasonably stressed” case?

Yes ☐ No ☒

Comment: This appears to be a case of expecting that "one size fits all" in requiring that certain scenarios be evaluated. Since the goal here is to improve reliability, it makes more sense to have transmission planners identify appropriate sentivities for area under study. The appropriate sensitivity is likely to vary depending on the portion of system being studied.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒

Comment: Use of sensitivities should not be required for Stability analysis, but the Standard should rather allow sensitivities at the discretion of the planning engineer. Due to the computationally intensive nature of these studies, a study rotation would be appropriate. For example, one year would be peak base case, next year off-peak case, and following year a sensitivity case. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: Long-term planning horizon studies are typically based on a number of assumptions regarding future conditions and uncertainties. While testing various load conditions, generator operation assumptions, and power interchange variables may be useful for modeling expected economic value, such analysis does not contribute to reliability.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☒

Comment: Yes, DSM should be considered in transmission studies, but should be limited to firmly contracted DSM resources that are demonstrably applicable for transmission capacity mitigation. DSM is better compared to supply-side resources as they are evaluated for reserve margin contribution. No, the challenge in considering DSM, is that Transmission Planners are not aware of DSM potential on the system and it must be communicated to them for consideration.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒

Comment: Sufficient analysis, including re-testing, must have been performed in creating the Corrective Action Plans. Requiring demonstration by the transmission planner that this is the basis of the Plans is superfluous.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: The current Corrective Action Plan should show the performance of the system with the best information available. These Plans will change year by year as conditions change and new information becomes available. Requiring that Plan projects from previous years may not be modified "without documentation" adds a additional unneeded paperwork.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not	No indirect (non-consequential) loss of load for single contingency events, else operator is in SOL precontingency without

	agree.	such planning.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Allow indirect (Non-Consequential) loss of load for events involving short duration outages, such as typical line outages.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	Do not allow indirect (Non-Consequential) loss of load for events involving long duration outages, such as transformer outages. (Tranformer outage could occur first).
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	Do not allow indirect (Non-Consequential) loss of load for events involving long duration outages, such as transformer outages.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: No indirect (Non-Consequential) loss of load for outage of single EHV element.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment: With the clarification that direct (Consequential) loss of load is associated with all outage elements: both SLG element and stuck breaker element.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	Note - No voltage limit for generator and transformer per Table 1, P4-4

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: The key word in this question is "dependent". Transfer is "firm" if DC line is in service.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

[1] System adjustment can be manual or automatic

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☒
Comment: Yes, we agree that appropriate induction motor loads should be modeled. No, it is not be practical to model all induction motor loads. There needs to be size and location considerations. Data is not readily available today.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Generation redispatch should not be performed for single contingencies. Generation redispatch is appropriate for multiple contingencies. Appropriate SPS and generation runback schemes should be allowed, where the system is designed with those schemes.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☒
Comment: Yes, where the transmission system is designed with these schemes. No, in general when there is no designed SPS or runback for the generator.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☒
Comment: No, this should be the exception, not the rule. Yes, there are mine mouth plants with DC outlet lines, which must be runback if the DC line trips. There are also generators which used to serve large on site loads. The large loads are gone (plants retired) and generator outlet is limited. There are also some generators which have known contingent outlet limits and the generators are OK with runback, if the contingency occurs.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: The use of SPS/RAS may be the appropriate transmission system design. If it is economic to mitigate the SPS, then upgrades should be made.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: SPS may be used if it maintains similar level of system reliability and security as transmission upgrades.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: The Midwest ISO appreciates the opportunity to offer the following recommendations:

1. Requirements for providing modeling data in R1. are redundant with the exising requirements of MOD-010-0, MOD-012-0, and MOD-016-0 through MOD-025-1. Adding these requirements to the TPL Standard is unnecessary and may create confusion.

2. The Standard does not address the return of direct (consequential) load loss following a contingent event. How long of an outage event acceptable?

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)			
Group Name:	**Midwest Reliability Organization (MRO)**		
Lead Contact:	**Tom Mielnik**		
Contact Organization:	**MRO**		
Contact Segment:	**10**		
Contact Telephone:	**563-333-8129**		
Contact E-mail:	**tcmielnik@midamerican.com**		

Additional Member Name	Additional Member Organization	Region*	Segment*
Neal Balu	WPS	**MRO**	10
Terry Bilke	MISO	MRO	10
Robert Coish	MHEB	MRO	10
Carol Gerou	MP	MRO	10
Jim Haigh	WAPA	MRO	10
Ken Goldsmith	ALTW	MRO	10
Tom Mielnik	MEC	MRO	10
Pam Oreschnick	XCEL	MRO	10
Dave Rudolph	BEPC	MRO	10
Eric Ruskamp	LES	MRO	10
Michael Brytowski	MRO	MRO	10
David Jacobson	MHEB	MRO	10
Ron Mazur	MHEB	MRO	10
27 additional MRO members	not mentioned above	MRO	10

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: The MRO could not agree on the correct definition.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Low probability of occurrence should be in reference to something to be more meaningful. The MRO suggests that the definition be changed to state "lower probability of occurrence than Planning Events."**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	

Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: This definition is too general. It could be interpreted that the performance studies include resource planning rather than transmission system planning, as well as, asset management. Asset management issues should be beyond the scope of this transmission planning standard. Asset management is an engineering discipline that would require a separate standard or standards and is still a developing activity, for example, there is no industry-wide practice for studying aging issues of transmission equipment while there are industry-wide practices for steady-state, stability, and short circuit modeling and planning of transmission systems. The MRO suggests that the word transmission be added to the definition when referring to needs, performance, and reinforcements and that references to asset management be deleted. Here is a proposed definition "Documented evalution of future Bulk Electric System TRANSMISSION needs by the use of TRANSMISSION SYSTEM performance studies that cover a range of assumptions regarding TRANSMISSION system conditions, time frames, future plans including TRANSMISSION IMPROVEMENTS and operating procedures and other factors." The words in all caps were added or inserted to replace the Drafting Team's original words.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: The words "Bulk Electric" should be added before "System".**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: The words "Bulk Electric" should be added before both occurences of "System".**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The Drafting Team has provided the appropriate level of detail by indicating that one or more of the following conditions are to be used. However, the MRO notes that R.2.1.3.1 should be changed to match R.2.4.3.1, that is, R.2.1.3. 1 should be changed to state "Variations in Load model assumptions."

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: This is unnecessary micro-management of the planning process. The MRO recommends that the Drafting Team proceed with the high-level requirement as provided with the minor changes recommended by the MRO in other parts of this comment form.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒

Comment: The MRO is okay with requiring the sensitivity studies but is concerned with the R.2.4.3.2 requirement as written in that it unnecessarily requires that the sensitivity studies to "simultaneous transfer" to include "non-firm transfers". The MRO recommends that this be changed to match R.2.1.3.2 "Modification of expected TRANSFERS." The MRO also questions the wording of R.2.4.3.4 which provides a more limiting description of the sensitivity to reactive. The MRO recommends that the wording of this requirement be changed to match R.2.1.3.4, "Variability and outages of reactive resources."

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: The models for Long-Term Transmission System Planning Horizon typically contain such uncertainy that the base planning is a sensitivity study iteself. The MRO believes that sensitivity studies in these years would be a waste of time.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒

Comment: DSM should already be in the load forecast and sensitivities to the load forecast variations are included in the near term planning horizon sensitivity analysis. Additional DSM shouldn't be part of the transmission planner's corrective plan. Additional DSM can be considered in the next planning cycle.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒

Comment: The MRO is concerned with this requirement particularly since the standard indicates that System Assessment shall be conducted each year while studies are not required each year. MRO members typically conduct this exercise at the time that studies are originally conducted with regard to improvements. By requiring a new study with improvements (some of which were justified in past studies) demonstrating that these improvements work essentially results in the Transmission Owner needing to clear a new unfair hurdle for improvements. This results in a requirement which will result in wide-spread non-compliance. The SDT should clarify that this requirement can be met by past studies. The MRO recommends that R2.7.2 be removed because it is redundant since development of the corrective action plan will have included these studies.

At some point the corrective action plan should be tested to verify the plan meets the performance requirements. The way the standard is written is that the transmission plan should be perfect for the entire planning horizon for all sensitivities tested. Any issues should be immediately addressed. The standard does not allow any time to develop the corrective plan through an open and transparent process. Based on the Nerc definition, a Corrective Action Plan is the list of actions and an associated timetable for implementation to remedy a specific problem. A Corrective Action Plan could mean that load forecasts at the station will be verified, facility ratings verified and alternatives to fix the identified problem to be determined before the next Planning Assessment. Standard R2.7 seems to be mixing the idea of a Corrective Action Plan with the original TPL idea of determining corrective plans to achieve required performance. A corrective plan wil be the end goal of a Corrective Action Plan.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐

Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒

Comment: The MRO disagrees with this requirement. This is an unnecessary requirement since each year Corrective Action Plans must meet the system performance requirements.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level (such as 1000 MW) of non-consequential load that is acceptable for such low probability events.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level (such as 1000 MW) of non-consequential load that is acceptable for such low probability events.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level (such as 1000 MW) of non-consequential load that is acceptable for such low probability events.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level (such as 1000 MW) of non-

		consequential load that is acceptable for such low probability events.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒

Comment: This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level of non-consequential load that is acceptable for such low probability events such as 1000 MW.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level of non-consequential load that is acceptable for such low probability events such as 1000 MW.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	The monopolar DC line words should be revised to "a single pole of a DC line".
Q28. P4-3: Loss of a generator followed by System adjustment followed	☒Agree. ☐Do not agree.	

[1] System adjustment can be manual or automatic

by loss of a Transmission circuit		
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: The MRO questions why interruptions of firm transfers are not allowed in other cases since load dropping is allowed for these cases.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment: The MRO commends the SDT in separating the two tables. The single table for both types of studies has generated confusion in the industry.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: The MRO sees the need for plant stability study requirements somewhere in NERC standards although adding this requirement into this study requires a rehash of the plant stability studies that are conducted throughout ten years or more in an annual assessment. This seems to be an unnecessary duplication. The MRO recommends that this requirement be deleted from this standard and that the SDT recommend to the NERC SAC that this requirement be covered by the appropriate future SAR.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment: In a breaker-and-1/3 or breaker-and-1/2 generating station, if one station bus is off-line for maintenance, faulting the other bus will kill the station, or at least cause major disruption with individual generators connected to other stations by separated lines or AC separated DC converter transformers via isolated station bays. That is certainly worthy of consideration as a feasible "extreme" event.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: The MRO agrees that R2.4.1 should provide for the inclusion of dynamic behavior of induction motor loads, however, recommends that there should be a limitation on only requiring such behavior where significant such as large motor loads over a certain MW amount. As written, it could be interpreted that the Transmission Planner is non-compliant if all induction motors are not represented.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Here are the adjustments that the MRO believes the MRO systems are presently designed to meet and what an MRO Augmentation Drafting Team is proposing to require its members to follow for Category B and C events: 1. Generation adjustments - Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation change is limited to that amount that can be accomplished within the allowed readjustment period. Due consideration shall be given to start up time and ramp rates of the units. 2. Generation rejection to the extent possible within the allowed readjustment period. Generation rejection shall not exceed the normal operating reserve of the generation reserve sharing pool to which the MRO Member belongs or of the MRO Member itself if the MRO Member self-provides generation reserves.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment:
Generally, the historical MRO practices and requirements have been to require that following a single contingency the loading of facilities are to be maintained within emergency ratings. Adjustments are allowed to move the system from conditions within emergency ratings to conditions within normal ratings. However, in a limited number of cases, the use of Special Protection Systems are used to initiate fast generation run back, generation rejection, or automatic tripping of a remote transmission facility to get below a longer term emergency rating (30 minutes or longer.) In some cases, these involve parts of the network where remote generation is connected to load where the costs of not using the SPS would involve substantial increased investments and environmental impacts.

Requirement 3.5 needs more clarification. What rating should not be exceeded?

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: The MRO believes the MRO systems are presently designed to meet system performance, in some cases, with the use of SPS to initiate fast generation runback, generation rejection, and automatic tripping of a remote transmission facility for a single contingency event. The fast generation runback or generation rejection should not exceed the normal operating reserve of the generation reserve sharing pool to which the planner belongs or of the planner itself if the planner self-provides generation reserves.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: SPS are often used in the MRO area to avoid unnecessary expenditures and environmental impacts. SPS are sometimes used to prevent instability. The SPS may intiate fast generation run back, automatic generation rejection, or automatic tripping of a facility for a remote event. The MRO notes that the scheme must be automatic, fast acting, consistent with short term equipment ratings. The MRO notes the folowing general conditions for adjustments, that perhaps would be useful in designing performance requirements for allowable system adjustments in addition to the description in Question 39: 1. Generation adjustments - Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation change is limited to that amount that can be accomplished within the allowed readjustment period. Due consideration shall be given to start up time and ramp rates of the units. 2. Capacitor and reactor switching - The number of capacitors and reactors, which may be switched, is limited to those which could be switched during the allowed readjustment period. This includes those capacitors and reactors that would be switched by automatic controls within the same period. 3. Adjustment of load tap changers (LTCs) to the extent possible within the allowed readjustment period. This includes both LTCs which would automatically adjust and those under operator control which could be adjusted within the readjustment period.
4. Adjustment of phase shifters to the extent possible within the allowed readjustment period.
5. An increase or decrease to the flow on HVDC facilities to the extent possible within the allowed readjustment period. 6. Transmission reconfiguration - Automatic tripping of transmission lines or transformers to the extent possible within the allowed readjustment period. 7. Automatic tripping of interruptible load or curtailment of or pre-determined redispatching of Firm Transmission Service to the extent possible within the allowed readjustment period.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: If the SDT proceeds with an approach that does not allow generation rejection for contingencies, the MRO will need to submit a regional difference. In certain areas of the MRO that are stability limited because of long lines to bring generation at the energy source (such as mine mouth plants, hydro plants, etc.) to the load, generation rejection is used to return from an emergency state to a normal state. If generation rejection is not allowed in these cases, extraordinary cost and extraordinary negative environmental impacts will result.

As an example, if one particular SPS is removed, new 500 kV transmission will be required between Winnipeg and Minneapolis at a cost of $1billion to the customers of MRO utilities.
.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment: The MRO commends the SDT on the difficult task of rewriting some of the most important NERC standards: the TPL standards. The MRO has a number of comments and suggestions.

1. Load modeling data in R1.1 and R1.2 do not belong in the TPL standards. It should be provided for in the MOD standards which provide the numerous load model data requirements. At a minimum, R1.2 should be revised to only require documentation of stressed system conditions. It is unnecessary and micro management to provide for "measurement during stressed System conditions". Further, it is unusual standards drafting to provide for a measurement of load in an assessment standard.

2. R1.4 should be revised to separate "known planned outages" from the rest of the requirement in separate sentences. This is because the reference to spare equipment outages does not have any bearing on the "known planned outages" requirement. Further the consideration of spare equipment strategy is not explained enough to understand what is required here. Further it is not clear as to what equipment must have consideration of spare equipment. The MRO recommends that R1.4 be rewritten as follows: "Known planned outages. Long-term forced outages for transformers with low-side voltages of 100 kV and above and generator step-up transformers should be identified where lack of spare transformers could result in outages of the transformers over the annual peak demand hour."

3. It is unreasonable for R1.5 to provide that planned facilities that are included in System Assessments include circuit breakers, and protection system equipment. These two items should be dropped from R1.5 since these are engineering details that are typically not available at the time that the System Assessment is made.

4. R.2.1.1 - The system peak load study requirements for studies for two of the near-term period seems to be excessive. The MRO recommends that only one year in the near-term period be required.

5. R2.6 should be deleted. The MRO believes that R2.1 and R2.4 are sufficient in describing when current studies are required. R2.6 will result in unnecessary restudy of the system. Alternatively, if R2.6 is kept, then the requirement should be a performance requirement, that as long as material changes do not require restudy then restudy is not required. The Transmission Planner and Planning Coordinator could be required to document why restudy is not required. Material changes should be expanded to refer to only those "significant" transmission line additions or generator additions.

6. R2.71 should be revised to delete "including the duration of interim Operating Procedures" or else the SDT should explain what is meant by this with additional information about what interim Operating Procedures are.

7. R2.7.1.1. should be revised to delete the requirement for project initiation date. This information is not typically available at the time of performing a System Assessment since this is detailed engineering information not pertinent to planning.

8. R2.7.5 should be deleted. The MRO believes the such detailed review of the status of the installation of projects to be beyond the scope of the TPL standard. Since NERC has no authority to require the installation of facilities, how does NERC have authority to require a review of the status of such facilities?

9. R3.2.1 and R3.2.2 seem unnecessary details that are micro-management of the planning process. Both requirements could be met by the transmission planner and planning coordinator with general statements of little value. Also, relay loadability is included in facility ratings and does not need to be covered in TPL.

10. In Table 1, "a shunt device (including FACTS devices)" is too general. Arresters and potential devices for metering and relaying are shunt devices. This should be changed to a specific listing such as: transmission capacitors (100 kV and above), transmission reactors (100 kV and above), …" and whatever other devices that the SDT intends to be included here.

11. In Table 1, Single pole of DC line should be moved to P1.

12. In both tables, "monopolar DC line" should be replaced with a "single pole of a DC line".

13. The revised tables are confusing in descriptions of various outages particularly since the interconnected transmission system has been planned for the past decade using the previous Table I. The SDT should limit its changes to Table I to a limited number of changes that have been known to cause issues in the past rather than raising the bar in a number of cases.

14. The Extreme Event descriptions in Table 1 should be revised to provide definitions of local area and wide area. 3 d. (3f.) and 3 c. (3 e.) are duplicates and should be combined. Wide area events as listed are such unusual events, which are difficult to analyze or model. The requirement should provide that the number of these wide area events to be studied is limited to a minimum of one.

15. The MRO does not believe that contingency reserve is necessarily synonymous with spinning reserve. The SDT should clarify note ii to Table 2.

16. The SDT should clarify the wording in the tables to better explain the events which are either above or below 300 kV. For example, in P5 change 1. IS IT "A Transmission circuit followed by a System adjustment above 300 kV followed by the loss of another Transmission circuit above 300 kV." or is it "A Transmission circuit followed by another Transmission circuit resulting in impacts on 300 kV facilities"?

P5 3. should be revised to say, "A transformer with a low side voltage rating above 300 kV followed by a System adjustment followed by the loss of another transformer with low side voltage rating above 300 kV." or is it "A transformer followed by the loss of another transformer resulting in impacts on 300 kV facilities."

17. R2.1.3 - R2.1.3 reguires sensitivity studies that involve many potential scenarios that would be difficult to create in a Planning Assessment. Planners can not model the unknown and to assume the unknown may be a difficult task to complete. Instead of "shall be run and", the language should be "shall be considered based on current knowledge of system including"

18. Extreme events description for common right-of-way should be defined. Does this include line crossing points? Suggest exclusion for corridors one mile or less similar to P9.1.

19. The language description of the even should be substantially the same between Table 1 and Table 2. Table 2 format is a bit cleaner with initial condition and event separated. Table 1 should follow this format.

20. The loss of a shunt device (e.g. SVC) should be added to Table 2 (P1.4).

21. Note 1ai. to Table 2 refers to event P3.2 which doesn't exist in the Table 2.

22. Note 1aii. to Table 2 allows generating units to "cascade trip" for certain events that were this would not be allowed in the existing TPL standards. The MRO recommends that the more of the events be listed in 1ai. so as to at least maintain reliability.

23. Note 1aiii talks about acceptable damping. NERC should have a standard requiring development and documentation of damping criteria by the planning coordinator.

24. P9 should be changed from referring to a monopolar or bipolar dc line to a single pole of a DC line.

THE FOLLOWING ARE RON MAZUR'S COMMENTS.

25. The MRO does not believe R1 is required in this standard. The modelling standards should cover the requirement of the data owners to provide data to the PC.
Further this data needs to be provided to the TP as well.

26. R1.4: requires planned outage data to be provided to planners. The MRO does not believe this is a requirement for planning. It is not economic to add facilities to accommodate future planned outages. Secondly, the Table 1 multiple contingencies already mandate that planners consider the impacts of an outage with system adjustment followed by testing for the next contingency.

27. R1.5: requires the PC to define “planned facilities” which should be included in the model. This will lead to inconsistency what is modelled, as experience has shown that there will be a wide range of assumptions in the definition. This standard should offer a definition for stakeholder debate. The SDT should clarify what is intended by including Protection System Equipment and control devices.

28. R2: The SDT should define the elements of an acceptable assessment in more detail.

29. The MRO recommends that the need to assess Plant Stability be removed from this standard. The generator connection standard and the proforma tariff interconnection process ensure the plant stability meets performance requirements. The System Assessment provides an overall assessment of the integrated system performance, which includes the impact of the plant. This requirement appears to be redundant.

30. R2.1: It is important to assess off peak loads with high simultaneous transfers as this is the period where extensive economic interchange occurs, and transient stability issues arise as less uneconomic peak units are off, leaving the load to be supplied by remote generation with reduced local reactive supply, voltage and damping control.

31. R2.1.3: The requirement for sensitivity cases is excellent. The SDT should consider:
R.2.1.3.1: separate real MW load variation and Power Factor variation
R.2.1.3.2: clarify the intent of modification of expected transfers. Does this apply to firm transfers only, or does it also encompass non-firm transfers.
..R.2.1.3.4: Instead of a sensitivity, the reactive devices should be included in the Table 1 &2 contingencies. If the intent is to investigate robustness to voltage instability, the SDT should clarify.
R.2.1.3.5: Generation additions/retirements should be removed as this is covered, or should be, by the interconnection standards. The SDT should clarify.the need for generation additions/retirement.

32. R2.2: The long term assessment should also include an off peak case with simultaneous transfers to provide some indication if the system performance is expected to degrade.

33. R2.3: The short circuit study is not a reliability assessment issue but a design issue that is more appropriately covered by a Facility Rating Standard. The time required to conduct and report on this analysis in an assessment is better spent on more contingency or sensitivity analysis.

34..R2.4: Similar to the comment on R2.1,. It is important to assess off peak loads with high simultaneous transfers as this is the period where extensive economic interchange occurs, and transient stability issues arise as less uneconomic peak units are off, leaving the load to be supplied by remote generation with reduced local reactive supply, voltage and damping control.

35. R2.4.1: Should be clarified to limit the detailed modeling to local areas where the planner expects an emerging voltage recovery issue due to unusually high concentration of induction motor load. This is a local issue, and a bulk system reliability issue that is imposed system wide. The MRO believes this should be moved to the sensitivity case requirements R2.4.3.

36. R2.4.3: Sensitivity Case requirements should mirror the steady state comments, subject to the suggestion provided above for R2.1.3. That is:
..R.2.4.3.1: should also include power factor variation (actually a separate requirement) as in the stability world, the dynamic modelling of load has a significant influence in meeting transient performance requirements.
R.2.4.3.2: I agree it should simultaneous non-firm transfers. This should be applied to the steady state sensitivity as well (see R.2.1.3.2).
..R.2.4.3.3: delete
..R.2.4.3.4: Needs to be clarified. See R.2.1.3.4.
. R.2.4.3.5: see R.2.1.3.5

37. R2.5: Plant stability analysis should be deleted.

38. R2.6.1: Nowhere else in the standard is there a requirement to assess reliability impacts of market structure changes, so why would a study become invalidated if there is a change in market structure. It would seem to me that the operation of any market would have to respect the reliability criteria.

39. R2.7: Corrective Action Plans: Is the intent that corrective action plans also address issues raised by the sensitivity studies. The MRO argument would be that it should not

be mandated. The plans are developed to meet base case needs which are based on expected load forecasts, transfers, etc. Sensitivity studies are done to measure the robustness of the base case plan. It should be left up to the Planner to decide if the plan is adequate based on the likelihood of the scenario studied, even if the sensitivity analysis shows some performance violations.

40 Also, if rationale is provided for contingencies selected as they are expected to be most severe, then by default those not selected are less severe. Why is there a requirement to explain why you did not select a contingency.

41. R3.4: Requires extra analysis compared to TPL-004-0. Developing mitigation for extreme events can require significant work. Since there is no requirement to implement corrective plans for extreme events, what is the purpose?

42. R3.5: Generator tripping should be added in addition to runback. Generator tripping is used extensively in regions where remote generation is delivered via long transmission. Generator tripping should be an available option for the planner to use as opposed to requiring justification as a regional difference.

43. R4: The requirement to assess Plant stability is redundant as this is assessed as part of the generator interconnection. It should be deleted.

44. R4.5.2: The MRO disagrees on the need to define mitigation for extreme events.

45. R4.6: Should be deleted.

46. R6: Requires distribution of results and "coordinating analysis of these results through an open and transparent process". Can the SDT clarify what the intent is? As written, it implies the PC/TP just shares assessment results with neighbours. The MRO believes there should be a requirement to conduct joint assessments on inter-regional transfer capability.

47. Table 1
Performance Requirements:
- As this is a steady state table, how does one assess if voltage instability, cascading outages or islanding occurs?
- Generator tripping for single contingencies should be added to the allowable actions.
- How did the SDT classify which event was single contingency vs. multiple contingency vs. extreme? Was statistical data analysed?
- What is a non-bus tie breaker? Is this any breaker that is not a bus tie breaker?
- Event P2-3 should be relocated to the P1 event category.
- What is the SDT rationale for defining bus faults >300 k as single contingency events? Is there any statistical dat to warrant this extra requirement? Now a Cat C? Since little load is served off >300 kV it may be a moot point.
- P6 single contingency: What is the justification for classify P6-2, a bipolar dc loss as a single contingency? The existing standard classifies this event as a Cat C multiple contingency event?
- P6-3: Why is a breaker fault classified as a single contingency? One would assume such a fault would be cleared by backup protection resulting in the loss of multiple elements?
- P9-1; Is there any justification for selection of one mile? Can it be two miles? More? Why not no more than 5% of line length? Would the fact that there is line shielding be justification for increased length?

48. Extreme Events
• Event 3.g: what is the rationale for distinguishing between old vs. new design for the loss of multiple lines due to icing? Is the SDT implying that new lines must be designed to prevent multiple line loss due to icing?

49. Table 2 Stability Performance

• MRO Comments on Table one for the same contingencies should also be applied here.

50. P6-2 should be a multiple contingency, as it is in the existing TPL standards.

51. P9-3: should be an extreme event.

52. P9-6: Please clarify the requirement to indicate that it relates to long lead times.

53. The definition for Angular Stability should be modified to allow planned tripping of a generator following a line trip. Why are generators allowed to pull out of synchronism for other planning events? This is cascading. The SDT should clarify if they are refering to local or regional damping modes in 1.a.iii.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Lewis Ross	
Organization:	Muscatine Power and Water	
Telephone:	563-262-3311	
E-mail:	lross@mpw.org	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☒ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☒	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☒Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.

- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☐

Comment: Leave it open so it can be driven by local issues including those not in the standards. i.e. Running near term criteria on the long term horizon, additional contingencies beyond currently required, etc. as appropriate for the area.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a “reasonably stressed” case?

Yes ☐ No ☐

Comment: Leave it open so it can be driven by local issues including those not in the standards. i.e. Running near term criteria on the long term horizon, additional contingencies beyond currently required, etc. as appropriate for the area.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐

Comment: If reasonable and appropriate and allow for local issues including those not in the standards..

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: Local issues may drive a different approach

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in

conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: We do not have DSM but I could see where it could be used to relieve overloads or low voltage.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☒
Comment: Large enough to ensure negative impacts will not occur. This could best be covered in regional studies. (See Q43 Comment #3)

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☐Do not agree.	See Q43 Comment #5.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☐Do not agree.	See Q43 Comment #5.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	See Q43 Comment #5.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	See Q43 Comment #5.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐
Comment: See Q43 Comment #5.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance

requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment: See Q43 Comment #5.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☐Do not agree.	See Q43 Comment #5.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	See Q43 Comment #5.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☐Do not agree.	See Q43 Comment #5.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☐Do not agree.	See Q43 Comment #5.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment: See Q43 Comment #5.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an

[1] System adjustment can be manual or automatic

assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Unless there is a reasonable reason to expect all the units to trip.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment: We have not seen this on our system based on the review of digital fault recorders (DFR). The difficulty with including induction motors is getting reasonable data from customers about their motors so they can be adequately modeled. (We did ask our consultant to include motor effect in our coordination study since the motors could act as a weak source.)

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Whatever the local entity sees as appropriate and is reasonable versus the cost of fixing the problem. (See Q43 Comment #3)

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Reasonable and workable.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: As long as they work and are reasonable - none. (See Q43 Comment #3)

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: Reasonable and workable. (See Q43 Comment #3)

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐

Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: Muscatine Power & Water (MPW) is a municipal utility with approximately 33 miles of 161 kV lines (2 lines) and 33 miles of 69 kV lines with three – 161/69 kV substations and seven – 69/13.8 kV substations. The service territory is approximately 24 square miles. Our last system peak was 149.9 MW on July 29, 1999 with a more recent peak of 146.9 MW on July 17, 2006 with generating capacity of approximately 253 MW from four units. The main problem we have is keeping up with the standards changes with our limited resources. We would suggest:

1. It was good to see the definitions section. We would also suggest including all acronyms including those in common use. Acronyms have become so common and they are now being reused to mean different things to different groups that for new people, multitasking individuals, or those not dedicated to a specific standard acronyms add confusion. Where possible, we would suggest using existing terms and, if appropriate, preferably already defined or have them defined in IEEE standard #100 dictionary.

2. Can you address adequate documentation? I'm not looking for detail formats or requirements but more minimum requirements and suggested layout etc. One of the problems I have during audits is how much documentation to provide without going over board. More is not good considering time requirements. Our goal is to make it easy for us and the auditors. We met the standard but have we proved it. Being a small utility with little impact on the bulk system how much should we provide?

3. In our region the MAPP Design Review Subcommittee (DRS) and in some cases the Subregional Planning Groups (SPGs) review new and proposed changes to facilities. In many cases they would have to approve any RAS or SPS and thus provide a peer review/reasonable and workable check.

4. R.2.6.1 - Being a small utility we are concerned about the planning study must be less than 3 years old. We budget for studies every three years but adjust that based on whether material changes have occurred to the system. Our last cycle was 6 years only because our load hasn't been growing and we still haven't hit our peak of 1999. Since we are dependent on consultants, we also have a concern for how long it can take for them to complete the study. Since we are small the bigger customer gets the attention. We do use the same criteria for near and long term planning horizons. We also participate in MAPP and ITWG studies for the annual and bulk system review and since our issues in studies are more local rather than the bulk transmission system. How should/could the sensitivity studies be covered for us at the regional level?

5. 300 kV and above questions: MPW is a small utility that doesn’t have any facilities above 161 kV or any DC lines. I can see requiring more stringent performance for EHV

and possibly lower voltage facilities in some cases, however, whether to allow the loss of Non-Consequential load should be left to local entities to decide since the cost of the "corrective action" could exceed the cost of the load loss and put undo burden on the customers. Depending on the type of load the customer may not want/be willing to pay for the extra reliability. If ordered, how will the cost be recovered? The cost should be recovered by the users not just the local customers.

Thanks for the opportunity to comment!

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Carol Sedewitz	
Organization:	National Grid	
Telephone:	(508) 389-3108	
E-mail:	carol.sedewitz@us.ngrid.com	

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: There are a few undefined terms in this definition: "Transmission System" and "interconnected Transmission System". The definition needs to specifically identify what should be modeled and in a manner consistent with other NERC definitions. The definition refers to Facility ratings rather than the general reference to FAC-008 & FAC-009**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Modify to "Events which are more severe,but have a lower probability of occurrence, than Planning Events".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☒Do not agree.
Q4. **Comment: "Transmission planning period that covers years six through ten", is sufficient for the standard."**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such	☒Agree. ☐Do not

as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Eliminate "capital" from the definition. Suggest changing wording to "Documented evaluation of future Bulk Electric System needs by use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including reinforcements and operating procedures. The corrective action plans may consider factors such as asset conditions and age."**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Propose, "Events for which Transmission performance requirements must be met".**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: A Plant Stability Study should be a part of a System Stability Study. The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: See comment on Q9; proposed modification, "Study of the System or portions of the System to determine whether unit and system angular Stability is maintained, power oscillations are damped, and voltages during the dynamic simulation stay within acceptable perfomance limits.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: Modify to, "The first year that a Tranmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner completes its annual studies."**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement to develop action plans for problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System shall be considered, and documentation with the rationale for the sensitivity testing shall be supplied. The sensitivity case(s) may include one or more of the following conditions:"

2.1.3.3 should refer only to planned facilities that may be delayed. 2.1.3.4 - "variability" is too vague for a standard; the standard needs to be more specific as to the intent. 2.1.3.7 should be consistent with 1.4. These comments also apply to 2.4.3.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement to develop action plans for problems highlighted as a result of one of the sensitivities.

Reasonably stressed conditions are dependent upon the study area under review and the standard is not likely to be able to be crafted to provide sufficent and consistent direction. However, it might be helpful if the standard clarified whether the base case should include any unplanned generator outages or whether, aside from potential sensitivities, unplanned generator outages are considered only through P1, P3 or P4 Contingencies. If the standard addresses unplanned generator outages only through P1, P3 and P4, then it is recommended that a mandatory sensitivity analysis, with required mitigation, include various potential combinations of a reasonable amount of unplanned outages. The combinations should be based on the part of the system that is under study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐

Comment: The standard is unclear whether or not it mandates the requirement to devleop action plans for problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System should be considered. Sensitivity case(s) might include among the following conditions:" 2.4.3 shold mimic 2.1.3 except in regard to load models.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: There is no need for sensitivity analysis.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: DSM should be included to the extent that its performance is sufficiently and consistently understood. The standard does not use the term "optimal" Therefore, the Drafting Team appears to be interpreting the Standard to require a vertically-integrated Planner to produce a so-called optimal-mix of resources plan. This would be an incorrect assumption and is not required. In areas with independent planners and competitive wholesale markets, it is sufficent to identify system needs and produce a plan that identifies regulated transmission solutions in the event that market-based resources (such as DSM) do not address those identified needs. Therefore, while DSM can be as effective a resource as generation, per Commission Orders, in areas with ISOs/RTOs and a competitive wholesale market, the NERC Standard cannot prescribe the development so-called optimized (as is suggesgted by the Drafting Team) resource-mix plans, as identified by a central planner.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐

Comment: The study area should be based upon planning expertise and knowledge of the system, giving due consideration to external impacts.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐

Comment: They should be viewed differently in the Near-Term. However, these should be defined terms.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐

Comment: It is unclear as to what the commited project is being removed from. Suggested language "…removed from the plan…".

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	Should also consider the initial loss of a transformer, followed by the loss of a Transmission circuit. This should state a transformer with a "high-side" rating above 300 kV.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	This should state a transformer with a "high-side" rating above 300 kV.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐

Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	If mitigation plans are required that are based on studies that already include unplanned generator outages, then some load loss may be reasonable following the subsequent loss of 2 additional generators.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	If mitigation plans are required that are based on studies that already include unplanned generator outages, then some load loss may be reasonable following the subsequent loss of an additional generator and a monopolar DC line
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	If mitigation plans are required that are based on studies that already include unplanned generator outages, then some load loss may be reasonable following the subsequent loss of an additional generator and a Transmission circuit
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	If mitigation plans are required that are based on studies that already include unplanned generator outages, then some load loss may be reasonable following the subsequent loss of an additional generator and a transformer

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐

[1] System adjustment can be manual or automatic

Comment: This should also apply to firm transfers via single or double circuit ac facilities as well. In either case, the transfer could be linked to dedicated facilities.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: As defined in R2.5, a Plant Stability Study should be a part of a System Stability Study. The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Difficult to envision how such an event would occur.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: This requirement is too specific and limited. Induction motors are only one component of a complex load model. Complex load models are not always necessary, nor are they always the most conservative, depending on the analysis that is being conducted. Where complex load models are required, they should be considered; this may involve use of complex motor and lighting loads or polynomial load representations with or without frequency dependence. This question also suggests the need for an industry standard regarding transient voltage recovery.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Manual or automatic adjustments should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment. Manual system adjustment should be allowed in between the multiple Contingencies described in P5, provided that the adjustment can be made between contingencies using short-term reserves (10-30 minute).

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: Generation runback should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐

Comment: However, this should only be allowed where failure of an automatic runback that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: Only allowed where the failure of an SPS that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Only allowed where SPS failure would not have significant adverse impact on the Bulk Electric System; non-Consequential loss of load should be allowed up to an amount potentially specified in the standard.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: System must remain stable with acceptable voltages and all equipment within applicable emergency limits.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment: We're not aware of any at this time. However, future modifications of the standard may highlight a need for regional variances.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: There should be a "P0" standard that applies to system performance without any contingencies.

Standard should be clear that stabiltiy analysis is not required for Long-Term Planning Assessment.

R.1.1 Load forecasts should be addressed in MOD standards, not TPL.

R 1.4 This should only refer to known long-term outages, not planned outages. Delete "including protective relays"; this is addressed through other provisions.

R.2.1 Shorten "Near-Term Transmission Planning Horizon Planning Assessment" to "Near-Term Planning Assessment".

R 2.2 Shorten "Long-Term Transmission Planning Horizon Planning Assessment" to "Long-Term Planning Assessment".

R2.1, 2.2, 2.3 & 2.4 – The initial paragraph should have identical language regarding 'annual', and 'current or past' aspects.

R2.1.1 There should not be a requirement to look at years one and two; a 5 year study should be sufficient. If there has been an ongoing 5 year study, there should be no major unexpected problems occurring in years 1 and 2. Studies of earlier years should only be required if an unanticipated event occurred that had not been considered in prior studies. The TPL should not address shorter term "Operating Studies" or operating issues.

R 2.2.1 Modify to "If any known projects have a lead time that is longer than ten years, the Planning Assessment shall be extended accordingly."

R 2.6 Steady-state, short circuit, and stability analysis should be required no more than every 5 years unless there is a significant change the system.

R 2.6.1 Remove reference to "market structure changes". The purpose of it's inclusion is unclear.

R 2.7.1.1 Project initiation date should be deleted. If it is retainted, it needs to be defined.

R 2.7.3 Committed and Proposed projects should be defined.

R 3.2.1/R 4.3 - What is the intent of this requirement? There should probably be an MOD associated with Generator Owner requirement to provide related generator protection/ limiter data or other plant information.

R 3.4/R 4.5.2 Remove the requirement to implement changes to reduce or mitigate the likelihood of such consequences of Extreme Events. This may not be reasonable or achieveable.

R 3.2 Sectionalizing schemes shall be considered when reflecting the post-contingent system.

R 3.2.2 - Propose deleting this. Line ratings should already take relay loadability into account.

R 3.3.2.1 - Propose deleting "expected duration". This would be dependent upon the damage to the element due to the iniating event and other factors.

R 3.3.2.2 - The requirements of this section do not match P6.

R 3.3.3 - Change introductory language to read "Those multiple Contingencies that are…"

R 3.5 - Generation tripping should be allowed as well as generation run-back. In addition, all performance requirements shall be met, rather than just meeting facility rating requirements. Suggested lanague "Manual and automatic generation run-back and/or generation tripping is allowed as a response to single and multiple Contingencies as long as the performance requirements of this standard are met." If these changes are accepted, R 3.6 can be deleted.

R 4 and R 4.1 - The language should be made similar to R 3 and R 3.1.

Suggest bringing language similar to R4.4 into R 3, the steady state section.

R 4.2 - High speed automatic reclosing schemes shall be considered.

R 6.3 - Change to read "Planning Coordinators of neighboring impacted areas".

Table 1 3 b and c Extreme Event descriptions are vague concepts that cannot be practically simulated. 3 d and e are not reasonable or practically useful to simulate.

Table 1, P8 - Language needs to be clarifed as to how the 300 kV threshold is to be treated for transformers. Is this for the high side, low side, or both sides? P5 is much clearer.

Table 2 - Clarification needs to be made that the faults being simulated are permanent faults. This can be addressed under the "Performance Requirements" portion at the beginning of the table, or modify each fault description.

Table 2 P9. Recommend that this be changed to require that faults should be on different phases of each of two adjacent transmission circuits on a multiple circuit transmission tower

Table 1, P9(6) and Table 2 P9 - It is unclear as to what is meant by "A spare transformer inserted to replace an outaged transformer followed by System adjustments". Unclear as to what is to be tested.

General comment - Transmission System is used throughout the document and is an undefined term

For any of the items when the standards may become more stringent, try to recognize that there is going to need to be a transition plan to meet compliance.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)	
Name:	NERC Transmission Issues Subcommittee
Organization:	NERC
Telephone:	
E-mail:	TIS@nerc.com

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☒ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: NERC Transmission Issues Subcommittee (TIS)

Lead Contact: David Till

Contact Organization: TVA

Contact Segment: Chairman of TIS

Contact Telephone: (423) 751-7147

Contact E-mail: bdtill@tva.gov

Additional Member Name	Additional Member Organization	Region*	Segment*
See attached TIS Roster			

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment: The definition should differentiate between powerflow and dynamics base cases**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment: MISOPERATION has to be qualified as being a misoperaiton on the system element that trips**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: The use of the term Extreme should be limited to those events that are truly extreme. A single line-to-ground fault with delayed clearing (for whatever reason) may require remote clearing of the fault, and trips multiple system elements, without time between elements being outaged. Such events are far too common occurrences to call them extreme.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs	☒Agree.

through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☐Do not agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Should not be limited to contingencies in the vicinity of the plant. Remove the terms "in the vicinity of the plant." Engineering judgement can then be used without having to define "vicinity." Plant instability can be caused by system events many (sometimes hundreds of) miles away. Plants were shaken off line in British Columbia due to the tripping of units in Arizona in June 2004.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☒
Comment: Since the long-term planning is completely couched in uncertainty, at least some generalized sensitivities should be required.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2

will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☒
Comment: Yes, if it can be counted on for relieving transmission constraints. Some DSM contracts do not allow for interruption for anything other than resource adequacy events, or have time-based or economics-based implementation limitations.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: All Corrective Action Plans should be tested on an interconnection-wide basis to screen for potential adverse impacts throughout the interconnection, not just the TOs area.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☒
Comment: No concensus in TIS after extensive disucussion, but it will be discussed further.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☒
Comment: Any revision to the Corrective Action Plan should be tested to ensure that the revised plan meets the precribed performance requirments. Documentation of that testing is appropriate.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar."

Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	Loss of a bus section is a single contingency. Non-consequential load loss should not be allowed.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	This becomes a differentiation between an event and a contingency - if there is time to adjust the system, it is really two events. Non-consequential load loss based on the first event is hard to fathom. Loss of load following the second event is either consequential to the second event (even if load was isolated by the first event) or non-consequential to the second event.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	See Q 21 Comment
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment	☐Agree. ☐Do not agree.	See Q 21 Comment

followed by loss of another transformer		

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: By its very nature, the event described is a breaker failure and the fault will typically need to be cleared by the next set of breakers, often remotely. Tripping out to the backup protection breakers typically can cause significant Consequential load loss. That should not be misconstrued as non-consequential load loss. Non-consequential load loss beyond that is unaceptable.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment: See comment to Q24.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a	☒Agree.	

[1] System adjustment can be manual or automatic

generator followed by System adjustment followed by loss of a transformer	☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment: TIS will discuss this in further review of the standards developement

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment: Although there are many simularities, separation of the testing requirements makes the standard far more understandable.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment: Planning Coordinators should study plant stability at the time of interconnection, and it should be reviewed for significant system or plant modifications that may impact the plant's stability.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment: Simultaneous loss of the entire generating stations have occurred on 4 occasions in the last 3 years, with simultaneous losses ranging from 1,100 MW to over 3,700 MW. It is imporatant to understand the stability implications to the system and other plants.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: If such known phenomena are not properly modeled, how can the resultant study results be expected to be correct and a proper prediction of future system behavior. The modeling shortcomings of the Western Interconnection prior to the August 1996 western blackout showed no potential stability problems for the events that occurred; the system proved otherwise.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: If system adjustments are allowed between events in steady state analysis, manual and automatic adjustments should both be allowed. However, in stability analysis, only automatic adjustments capabilities that are actually in place should be used.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment: This is simply a recognition that the system operators will take action to return the system to a stable and secure operating posture following an event.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that

must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: This is simply a recognition that the system operators will take action to return the system to a stable and secure operating posture following an event. This is also common practice in generator protection/controls for generators with multiple GSUs for loss of one of the GSUs.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: No special conditions required as long as the RAS or SPS are tested to meet the performance requirements.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: There may be some in the application of RAS or SPS for N-1 contingencies.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:

TIS Additional Comments to First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

October 26, 2007

1. In definition of "CONSEQUENTIAL LOAD," misoperations need to be defined better or removed, i.e. inadvertent tripping of elements due to protection system failure, including inadvertent SPS operation, may cause loss of load NOT connected to the element tripped off. In context of the definition, it appears that the misoperation should be on the protection system for the element that is tripped. {PARTLY COVERED}
2. Even when post-contingency voltage remains within prescribed limits, some voltage-sensitive customer load could still be dropped off due to their inherent sensitivity to allowed changes in voltage. Should such cases be considered as dropping non-consequential load or are the performance requirements met as long as post-contingency voltage stays within the prescribed limits? Such load losses can rarely be predicted by steady state analysis unless the loads and their distinct characteristics are explicitly modeled, but may be detectible in dynamic analysis since it is often the first swing voltage excursion that trips such loads.
3. Assuming the standard is passed, especially if the bar is raised, there should be some reasonable implementation period specified to allow entities that do not meet the standard's requirements presently and time to implement changes to become compliant.
4. Why is there a 300 kV threshold? Is there evidence that increasing the redundancy of the high voltage network will provide the largest reliability benefits?
5. Need to specifically define when it is OK to use "permanent" SPSs to meet performance requirements following the first contingency, i.e. separating a balance island should be OK. It is OK to utilize temporary SPS while the permanent corrective measure is being put in place.
6. Need to define, perhaps in the list of definitions, what is the "bus-tie breaker." Differentiation of center breakers in breaker-and-one-half schemes is a crucial item not to be subject to interpretation and possible confusion.
7. Need to clarify that "stuck breaker", regardless of whether cause by protection system failure, breaker failure to operate, or a slow breaker, is de-facto delayed clearance and causes additional contingency (ies).
8. Firm Transfer Cell for P3 does not make sense.
9. Need to strengthen the notion, in the bullets at the top of Table 1, that the assessment should also cover n-0 or "normal state (seems to be adequately covered in the body of the standard, but does not jump out from the Table 1 bullets at the head of the table.)
10. Include SHUNT DEVICES in P3–P9 planning contingencies. The same comment is applicable for stability table.

11. Need to clearly specify what documentation would be required to fulfill the standard's requirements for assessing extreme contingencies.
12. Replace "all" in the Extreme Events subheading with a more appropriate term.
13. Replace "all" in the table for Extreme Events for both Steady State and Stability tables with a more appropriate term to manage documentation requirements.
14. Use different designations for planned and extreme events in steady state and stability tables, e.g. PS and ES for steady state and PD and ED for stability (D for dynamic).
15. Throughout the tables, do not refer to "internal" breaker faults but use breaker fault instead. Faults can occur internal to the breaker, flashed bushings, or a fault (on or within) a free-standing CT associated with the breaker.
16. Modify bullet 5 in the Stability Table to include SPS failures to read:

    > “Simulate the removal of all elements that Protection Systems, SPS or RAS systems, and controls are expected to disconnect for each Contingency.”

    If an SPS or RAS is expected to operate for a contingency, it must be modeled as such for that contingency study.
17. In R1.2 need to add "for the period analyzed" and defined what "stressed" conditions means.
18. In R 2.1.3.7 need to insert "long-term" in front of "transmission outages." There is also a need to clarify/describe/define what long-term transmission outage is.
19. There are concerns, particularly for NON-vertically integrated TPs, about need of including Plant Stability requirements.
20. Define what "material" change is in R2.5.2.
21. Presumably the standard will be stamped with a CEII designation
22. Additional granularity should be included showing the correlation between Requirements and their applicability to any of the Functional Model Entities cited in the Standard.

23. Obligations to study and share results of the following should be clear in the TPL Standards:

    - Analysis of impacts on your system for contingencies outside of your system footprint.
    - Analysis of impacts on other systems for contingencies within your system. The owners of the other systems should be notified of your findings and joint analysis should be done if warranted.
    - Powerflow and stability analysis of contingencies that have interconnection-wide impacts. This may best be accomplished through modifications to existing standard TPL-005.

Transmission Issues Subcommittee

Chairman	David Till Manager, Transmission Planning	Tennessee Valley Authority 1101 Market Street MR 5G Chattanooga, Tennessee 37402	(423) 751-7147 bdtill@tva.gov
Past Chairman	Kenneth A. Donohoo, P.E. Director System Planning	Oncor Electric Delivery 2233-B Mountain Creek Parkway Dallas, Texas 75211	(214) 743-6823 (972) 263-6710 Fx kdonoho1@ oncor.com
Correspondent	Kirit S. Shah	P.O. Box 66149 (Mail code 635) St. Louis, Missouri 63166	(314) 554-3542 (314) 554-3268 Fx kshah@ameren.com
Correspondent	Anthony Alford Staff Engineer	CenterPoint Energy P.O. Box 1700 Houston, Texas 77251	(713) 207-2265 anthony.alford@ centerpointenergy.co m
ERCOT	Wesley Woitt Supervising Engineer	CenterPoint Energy P.O. Box 1700 Houston, Texas 77251	(713) 207-2760 wesley.woitt@ centerpointenergy.co m
FRCC	Hector Sanchez Supervisor, Bulk Transmission	Florida Power & Light Co. 4200 W. Flagler Street, TSP/LFO Miami, Florida 33134	(305) 442-5062 (305) 442-5790 Fx hector_sanchez@ fpl.com
MRO	Dale Burmester Manager, Access/Transmission Planning	American Transmission Company, LLC 2 Fen Oak Court Madison, Wisconsin 53718	(608) 877-8109 (608) 444-2447 Fx dburmester@ atcllc.com
NPCC	Thomas J. Gentile Director, Technology Transfer	National Grid USA 25 Research Drive Westborough, Massachusetts 01582	(508) 389-3799 (508) 389-4405 Fx thomas.gentile@ us.ngrid.com
RFC	Eric M. Mortenson Senior Engineer	Exelon Energy Delivery Two Lincoln Centre 9th Floor Oakbrook Terrace, Illinois 60181	(630) 576-6898 (630) 576-6354 Fx eric.mortenson@ exeloncorp.com
RFC	Bernard M. Pasternack, P.E. Managing Director - Transmission Asset Management	American Electric Power 700 Morrison Road Gahanna, Ohio 43230-8250	(614) 552-1600 (614) 552-2602 Fx bmpasternack@ aep.com
RFC	William Whitehead General Manager, Transmission and Interconnection Planning	PJM Interconnection, L.L.C. 955 Jefferson Avenue Valley Forge Corporate Center Norristown, Pennsylvania 19403-2497	(610) 666-4561 (610) 666-2296 Fx whitew@pjm.com

SERC	Mark Byrd Manager - Transmission Planning	Progress Energy Carolinas	(919) 546-7937 (919) 546-2684 Fx mark.byrd@ pgnmail.com
SPP	Jay Caspary Director, Engineering	Southwest Power Pool 415 North McKinley Suite 140 Little Rock, Arkansas 72205	(501) 614-3220 (501) 666-0376 Fx jcaspary@spp.org
WECC	Branden Sudduth Associate Staff Engineer	Western Electricity Coordinating Council 615 Arapeen Drive Suite 210 Salt Lake City, Utah 84108	(801) 582-0353 (801) 582-3918 Fx branden@wecc.biz
Cooperative	To Be Named		
Customer	To Be Named		
Federal	To Be Named		
Investor Owned Utility	W. Perry Stowe Director, Transmission Planning Department	Southern Company Transmission Company Bin 13N-8183 P.O. Box 2641 Birmingham, Alabama 35291-8183	(205) 257-6138 (205) 257-1040 Fx wpstowe@ southernco.com
IPP	Scott M. Helyer Vice President, Transmission	Tenaska, Inc. 1701 E. Lamar Blvd. Suite 100 Arlington, Texas 76006	(817) 462-1512 (817) 462-1510 Fx shelyer@tnsk.com
ISO/RTO	Jeffrey R. Webb Director of Planning	Midwest ISO, Inc. 701 City Center Drive Carmel, Indiana 46032	(317) 249-5412 (317) 249-5910 Fx jwebb@ midwestiso.org
Power Marketer	Israel Melendez Vice President, Grid Optimization	Constellation Energy Commodities Group 111 Market Place, Suite 500 Baltimore, Maryland 21202	(410) 470-5268 (410) 468-3540 Fx izzy.melendez@ constellation.com
State/Municipal	To Be Named		
TDU	To Be Named		
Canada	Yury Tsimberg Manager, Asset Strategies and Standards	Hydro One, Inc. 483 Bay Street North Tower, 15th Floor M5G 2P5 Toronto, Ontario M5G 2P5	416-345-5867 416-345-5443 Fx Yury.Tsimberg@ HydroOne.com
Correspondent	Thomas W. Green Principal Transmission Planning Engineer	Xcel Energy, Inc. 550 15th Street Suite 700 Denver, Colorado 80202-4205	(303) 571-7223 (303) 571-7877 Fx thomas.green@ xcelenergy.com

Correspondent	I. Paul McCurley Manager, Power Supply	National Rural Electric Cooperative Association 4301 Wilson Boulevard MC EP11-252 Arlington, Virginia 22203-1860	(703) 907-5867 (703) 907-5517 Fx paul.mccurley@nreca.coop
NRECA	Patricia E. Metro	National Rural Electric Cooperative Association 4301 Wilson Blvd. Mail Code EP11-253 Arlington, Virginia 22203	(703) 907-5817 (703) 907-5517 Fx patti.metro@nreca.coop
Correspondent	Guy V. Zito Assistant Vice President of Standards	Northeast Power Coordinating Council, Inc. 1515 Broadway 43rd Floor New York, New York 10036	(212) 840-1070 (212) 302-2782 Fx gzito@npcc.org
NPCC Alternate	Hai Quoc Le Manager, System Planning and Protection	Northeast Power Coordinating Council, Inc. 1515 Broadway 43rd Floor New York, New York 10036-8901	(212) 840-1070 (212) 302-2782 Fx quoc@npcc.org
ISO/RTO Alternate	Steve Corey Manager, Transmission Planning	New York Independent System Operator 5172 Western Turnpike Altamont, New York 12009	(518) 356-6134 (518) 356-6208 Fx scorey@nyiso.com
OC Liaison	To Be Named		
	Eric H. Allen Senior Engineer of Reliability Performance and Events Analysis	North American Electric Reliability Corporation 116-390 Village Boulevard Princeton, New Jersey 08540-5721	(609) 452-8060 (609) 452-9550 Fx eric.allen@nerc.net
PC Observer	James K. Robinson Bulk Power Analysis Manager	PPL Electric Utilities Corp. 2 North 9th Street Allentown, Pennsylvania 18101	(610) 774-4554 (610) 774-4116 Fx jkrobinson@ieee.org
NERC Staff Coordinator	Robert Cummings Director of Event Analysis & Information Exchange	North American Electric Reliability Corporation 116-390 Village Boulevard Princeton, New Jersey 08540-5721	(609) 452-8060 (609) 452-9550 Fx bob.cummings@nerc.net
NERC Staff	John L. Seelke, Jr. Manager of Planning	North American Electric Reliability Corporation 116-390 Village Boulevard Princeton, New Jersey 08540	(609) 452-8060 (609) 452-9550 Fx john.seelke@nerc.net

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Kathleen Goodman	
Organization:	ISO New England	
Telephone:	(413) 535-4111	
E-mail:	kgoodman@iso-ne.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☒ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☒	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: There are a few undefined terms in this definition: "Transmission System" and "interconnected Transmission System". The definition needs to specifically identify what should be modeled and in a manner consistent with other NERC definitions. The definition refers to Facility ratings rather than the general reference to FAC-008 & FAC-009**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Modify to "Events which are more severe,but have a lower probability of occurrence, than Planning Events".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☒Do not agree.
Q4. **Comment: "Transmission planning period that covers years six through ten", is sufficient for the standard." Suggest changing the name to Long-Term Planning Assessment.**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: Suggest changing the name to Near-Term Planning Assessment.**	
Q6. **Non-Consequential Load Loss:** Load loss other than	☒Agree.

Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Eliminate "capital" from the definition. It is not defined or consistently applicable to the standard. Reference to vague "other factors, such as asset conditions and age" should be removed from this standard; there are no consistent definitions or industry standards on which to base this requirement, nor does it appear to be a necessary addition to the standard.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Propose, "Events for which Transmission performance requirements must be met".**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: See comment on Q9; proposed modification, "Study of the System or portions of the System to determine whether unit and system angular Stability is maintained, power oscillations are damped, and voltages during the dynamic simulation stay within acceptable perfomance limits.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: Modify to, "The first year that a Tranmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner completes its annual studies."**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement to develop action plans for problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System shall be considered, and documentation with the rationale for the sensitivity testing shall be supplied. The sensitivity case(s) may include one or more of the following conditions:"

2.1.3.3 should refer only to planned facilities that may be delayed. 2.1.3.4 - "variability" is too vague for a standard; the standard needs to be more specific as to the intent. 2.1.3.7 should be consistent with 1.4. These comments also apply to 2.4.3.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement develop action plans for problems highlighted as a result of one of the sensitivities.

Reasonably stressed conditions are dependent upon the study area under review and the standard is not likely to be able to be crafted to provide sufficent and consistent direction. However, it might be helpful if the standard clarified whether the base case should include any unplanned generator outages or whether, aside from potential sensitivities, unplanned generator outages are considered only through P1, P3 or P4 Contingencies. If the standard addresses unplanned generator outages only through P1, P3 and P4, then it is recommended that a mandatory sensitivity analysis, with required mitigation, include various potential combinations of a reasonable amount of unplanned outages. The combinations should be based on the part of the system that is under study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐

Comment: The standard is unclear whether or not it mandates the requirement to devleop action plans for problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System should be considered. Sensitivity case(s) might include among the following conditions:" 2.4.3 should mimic 2.1.3 except in regard to load models.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: There is no need for sensitivity analysis.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: DSM should be included to the extent that its performance is sufficiently and consistently understood. The standard does not use the term "optimal" Therefore, the Drafting Team appears to be interpreting the Standard to require a vertically-integrated Planner to produce a so-called optimal-mix of resources plan. This would be an incorrect assumption and is not required. In areas with independent planners and competitive wholesale markets, it is sufficent to identify system needs and produce a plan that identifies regulated transmission solutions in the event that market-based resources (such as DSM) do not address those identified needs. Therefore, while DSM can be as effective a resource as generation, per Commission Orders,

in areas with ISOs/RTOs and a competitive wholesale market, the NERC Standard cannot prescribe the development so-called optimized (as is suggesgted by the Drafting Team) resource-mix plans, as identified by a central planner.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: The study area should be based upon planning expertise and knowledge of the system, giving due consideration to external impacts.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: They should be viewed differently in the Near-Term. However, these should be defined terms.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: It is unclear as to what the commited project is being removed from. Suggested language "…removed from the plan…".

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Given the low probability of extended overlapping outages of overhead facilities, systems have been designed assuming that load shedding following the loss of a second transmission line is permissible. Eliminating any allowance for load shedding for this condition may require significant system expansion and cost to to customers. However, it would be reasonable to consider establishing an upper bound to the amount of load that could be shed for these purposes.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Should also consider the initial loss of a transformer, followed by the loss of a Transmission circuit. This should state a transformer with a "high-side" rating above 300 kV.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	This should state a transformer with a "high-side" rating above 300 kV.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of 2 additional generators.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a monopolar DC line
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a Transmission circuit
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a transformer

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm

[1] System adjustment can be manual or automatic

transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: This should also apply to firm transfers via single or double ac facilities as well. In either case, the transfer could be linked to dedicated facilities.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Difficult to envision how such an event would occur.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: This requirement is too specific and limited. Induction motors are only one component of a complex load model. Complex load models are not always necessary, nor are they always the most conservative, depending on the analysis that is being conducted. Where complex load models are required, they should be considered; this may involve use of complex motor and lighting loads or polynomial load representations

with or without frequency dependence. This question also suggests the need for an industry standard regarding transient voltage recovery.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Manual or automatic adjustments should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment. Manual system adjustment should be allowed in between the multiple Contingencies described in P5, provided that the adjustment can be made between contingencies using short-term reserves (10-30 minute).

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: Generation runback should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐

Comment: However, this should only be allowed where failure of an automatic runback that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: Only allowed where the failure of an SPS that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Only allowed where SPS failure would not have significant adverse impact on the Bulk Electric System; non-Consequential loss of load should be allowed up to an amount potentially specified in the standard.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: System must remain stable with acceptable voltages and all equipment within applicable emergency limits.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☒
Comment: Unsure due to ambiguities in the standard. Depending upon the final standard, New England may need exceptions for existing facilities or allowance for a transition period to develop a compliance plan.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: There should be a "P0" standard that applies to system performance without any contingencies.

Standard should be clear that stabiltiy analysis is not required for Long-Term Planning Assessment.

R.1.1 Load forecasts should be addressed in MOD standards, not TPL.

R 1.4 This should only refer to known long-term outages, not planned outages. Delete "including protective relays"; this is addressed through other provisions.

R.2.1 Shorten "Near-Term Transmission Planning Horizon Planning Assessment" to "Near-Term Planning Assessment".

R 2.2 Shorten "Long-Term Transmission Planning Horizon Planning Assessment" to "Long-Term Planning Assessment".

R2.1, 2.2, 2.3 & 2.4 – The initial paragraph should have identical language regarding 'annual', and 'current or past' aspects.

R2.1.1 There should not be a requirement to look at years one and two; a 5 year study should be sufficient. If there has been an ongoing 5 year study, there should be no major unexpected problems occurring in years 1 and 2. Studies of earlier years should only be required if an unanticipated event occurred that had not been considered in prior studies. The TPL should not address shorter term "Operating Studies" or operating issues.

R 2.2.1 Modify to "If any known projects have a lead time that is longer than ten years, the Planning Assessment shall be extended accordingly."

R 2.6 Steady-state, short circuit, and stability analysis should be required no more than every 5 years unless there is a significant change the system.

R 2.6.1 Remove reference to "market structure changes". The purpose of it's inclusion is unclear.

R 2.7.1.1 Project initiation date should be deleted. If it is retainted, it needs to be defined.

R 2.7.3 Committed and Proposed projects should be defined.

R 3.2.1/R 4.3 - What is the intent of this requirement? There should probably be an MOD associated with Generator Owner requirement to provide related generator protection/ limiter data or other plant information.

R 3.4/R 4.5.2 Remove the requirement to implement changes to reduce or mitigate the likelihood of such consequences of Extreme Events. This may not be reasonable or achieveable.

R 3.2 Sectionalizing schemes shall be considered when reflecting the post-contingent system.

R 3.2.2 - Propose deleting this. Line ratings should already take relay loadability into account.

R 3.3.2.1 - Proposed deleting "expected duration". This would be dependent upon the damage to the element due to the iniating event and other factors.

R 3.3.2.2 - The requirements of this section do not match P6.

R 3.3.3 - Change introductory language to read "Those multiple Contingencies that are…"

R 3.5 - Generation tripping should be allowed as well as generation run-back. In addition, all performance requirements shall be met, rather than just meeting facility rating requirements. Suggested lanague "Manual and automatic generation run-back and/or generation tripping is allowed as a response to single and multiple Contingencies as long as the performance requirements of this standard are met." If these changes are accepted, R 3.6 can be deleted.

R 4 and R 4.1 - The language should be made similar to R 3 and R 3.1.

Suggest bringing language similar R4.4 into the R 3, the steady state section.

R 4.2 - High speed automatic reclosing schemes shall be considered.

R 6.3 - Change to read "Planning Coordinators of neighboring impacted areas".

Table 1 3 b and c Extreme Event descriptions are vague concepts that cannot be practically simulated. 3 d and e are not reasonable or practically useful to simulate.

Table 1, P8 - Language needs to be clarifed as to how the 300 kV threshold is to be treated for transformers. Is this for the high side, low side, or both sides? P5 is much clearer.

Table 2 - Clarification needs to be made that the faults being simulated are permanent faults. This can be addressed under the "Performance Requirements" portion at the beginning of the table, or modify each fault description.

Table 2 P9. Recommend that this be changed to require that faults should be on different phases of each of two adjacent transmission circuits on a multiple circuit transmission tower

Table 1, P9(6) and Table 2 P9 - It is unclear as to what is meant by "A spare transformer inserted to replace an outaged transformer followed by System adjustments". Unclear as to what is to be tested.

General comment - Transmission System is used throughout the document and is an undefined term

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **[Due Date in bold]**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name: Walter A Pfuntner, PhD, PE		
Organization: New York Independent System Operator		
Telephone: 518.356.6290		
E-mail: wpfuntner@nyiso.com		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☒ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☒	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. The SDT has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the SDT are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890 and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The SDT did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. The SDT organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The SDT determined that the requirements and analysis for Steady State are different from those for stability. As such, the SDT separated the analysis requirements and created two performance requirement tables.

The SDT recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The SDT has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The SDT has not addressed Measures, Risk Factors, Violation Severity Factors or Time Horizons at this time. These will be addressed when the SDT has better defined the requirements of the standard.

For questions where you agree with the SDT, please state that you agree and if available, please provide supporting documentation. If you disagree with the SDT, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you

believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the SDT would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the SDT is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒ Agree. ☐ Do not agree.
Q1. **Comment:** NYISO Agrees	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒ Agree. ☐ Do not agree.
Q2. **Comment:** NYISO Agrees	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐ Agree. ☒ Do not agree.
Q3. **Comment:** An alternate wording is suggested. Events which are more severe and have a lower probability of occurrence than Planning Events.	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒ Agree. ☐ Do not agree.
Q4. **Comment:** NYISO Agrees ~~long-term period should start at five years.~~	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers Years One through five.	☒ Agree.

	☐Do not agree.
Q5. **Comment:** NYISO Agrees	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment:** ~~An element(s) that is removed from service due to fault clearing action or mis-operation may be the cause of the low voltage or frequency. Loss of load in that case should be considered a consequence of the element being removed.~~ Suggest that examples not be listed or a more exhaustive list be developed.	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment:** **The word "Documented" is unnecessary. Suggest simplifying the definition to: Evaluation of future BPS needs to meet forecast demand under the assumed system conditions for the time frame studied.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment:** **Circular logic. Suggest: Events which need to be considered in planning assessments to evaluate Transmission system performance.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment:** **"Contingencies" should be replaced with "Planning Events". "in the vicinity of the plant" is too restrictive.** **Suggest: Study of an individual generating plant's capability to remain in synchronism with damping power oscillation for various Planning Events.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment:** **The study is an assessment.** **Suggest: Study of the System or portions of the System to assess the System's performance in the domain of angular stability, inter-area oscillations and voltage profile during dynamic simulation.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:** NYISO Agrees	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions", FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The SDT has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: NYISO does not support the introduction of sensitivity testing in the Planning Standards as a requirement. Sensitivity testing should be dictated by the local needs and system characteristics. The nature of planning studies incorporates assumptions that would make sensitivity analysis difficult to interpret.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: See comment to Q12. Additionally, what is the definition of "reasonably stressed"?

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒

Comment: See comments to Q12 & Q13.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year 6 and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: NYISO does not agree with the requirement of sensitivity studies in the near-term or long-term.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If Yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: NYISO suggests that the impact included in studies should consider past performance of DSM participants.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: **NYISO Agrees**

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐

Comment: **NYISO Agrees**

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: **NYISO Agrees**

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable BES that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the SDT attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The SDT is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the SDT to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL Standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	**NYISO Agrees**
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	We are assuming the second circuit is un-related to the first. If that is not the intent then it contracts the loss of multiple related circuits (same tower or protection zone) for which non-consequential load loss is allowed.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	Same comment as with Q21.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	Same comment as with Q21.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: **NYISO Agrees**

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment: NYISO Agrees

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	NYISO Agrees
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	NYISO Agrees
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	NYISO Agrees
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	NYISO Agrees

The performance requirement for the following event may be considered less stringent than the existing TPL Standards - P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: NYISO agrees from a reliability aspect.

[1] System adjustment can be manual or automatic

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☒

Comment: Only the difference between steady-state and stability analysis should be the performance requirements. The list of contingencies should be identical regardless of the type of analysis.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐

Comment: NYISO agrees with the concept of splitting plant and system stability studies, but only in the area of performance requirements. The studied contingencies should be identical.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment: Examples of loss of entire generation station: Complete loss of right-of-way exiting facility, simultaneous relay operations due to common cause or mode.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐

Comment: **NYISO Agrees**

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: ——Automatic: Pre-determined ranges of AVR, excitation system, stabilizer and governor. Manual: switching and PAR adjustments covered by applicable operating procedures

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: ——What is the difference between a SPS and RAS? Would not one term be sufficient? SPSs should not be considered a permanent solution. They should only be used as a stop gap before a permanent solution can be implemented.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐

Comment: Testing scenarios will have to be developed on a case by case basis depending on the design of the SPS. There is not universal rule that can be made for these unique cases.

The SDT has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: As stated previously SPSs shold only be a temporary solution used to protect elements prior to a permanent solution implementation.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Must be temporary, approved by the NYSRC, tested annually with evidence of preventive maintenance submitted annually.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: This would be dependent on the characteristics of each unique protection scheme.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☐ No ☒
Comment:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	James R. Manning, Robert S. Beadle	
Organization:	North Carolina Electric Membership Corporation	
Telephone:	(919) 645-2415, (919) 875-3135	
E-mail:	james.manning@ncemcs.com, Bob.Beadle@NCEMCS.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☒	4 — Transmission-dependent Utilities
☒ **RFC**	☒	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	**Additional Member Organization**	**Region***	**Segment***

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: The term "mis-operation" introduces ambiguity into the definition, and should be deleted. The definition needs further clarification for consequential and non-consequential loads. For example, loads served downstream from the faulted element but not directly connected should also be considered to be consequential loads.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: A number of the non-extreme events also have a low probability. Recommend change the word to "lower." The definition for "Extreme Events" should reference Table 1.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such	☒Agree. ☐Do not

as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☐Do not agree.
Q7. **Comment: Generally, we agree but would request NERC to clarify accounting for asset conditions and age within planning assessments. Wouldn't these already be taken into account in the FAC-008 & FAC-009 ratings?**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Change to: "Events that are simulated or assessed to test the transmission system to ensure that performance requirements are met."**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: This definition could use further clarification to eliminate inconsistencies in how it may be interpretted. Operations planning horizons may typically be 13 to 18 months from the current date due to the reality that transmission upgrades to address operational performance issues may not be able to be implemented inside this period. Some may assume a 24-36 month operations planning window. Based on this assumption, Year 1 could start anywhere from 13 months from the current date to as much as 37 months from the current date.**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii “Sensitivity studies and critical system conditions” FERC provided direction to consider a full range of

variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: There should be a stakeholder process for all entities (all Load-Serving Entities and Transmission Customers) involved or impacted within the defined area to provide input to determine which sensitivity cases are to be performed and the appropriate number of cases that need to be evaluated. Not every sensitivity case should be required for every system.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The standard should offer guidance but what constitutes a "reasonably stressed" case should be left to a stakeholder process as noted in Q12 with some discretion of the entity performing the study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐

Comment: The entity performing the studies should be allowed to determine the appropriate sensitivity studies that need to be evaluated with a stakeholder process for those impacted by these studies as noted above. An alternate approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency. Stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☒

Comment: Some sensitivity analysis in the long term years should be done (90/10 load with higher than expected transfers and/or delayed baseload generation) so that higher voltage issues are adequately tested to identify long lead time upgrades, in a similar manner as was done to justify the backbone projects that have been identified in the PJM Interconnection. A stakeholder process should be used by the entity performing the study to complile input on impacted LSEs and other Transmission Customers.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: It should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is considered firm.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐

Comment: Re-testing should be required particularly where the correction may impact network flows. The study area should be discussed within a stakeholder process to the TP may compile input from network customers or LSEs that might be affected by the analysis.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: Projects that are underway (i.e. being built) and are not subject to be potentially delayed and are absolutely needed for reliability should be differentiated between those that are not. Perhaps definitions for each of these terms should be considered for clarification.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to “raise the bar.” Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	Although this is a relatively low probability event, we do agree that it should be assessed given the widespread effects. It may not justify the need for a network upgrade but at least deserves consideration for an operating or corrective action procedure should the event occur. Also, given this analysis might be new for some TPs, consideration

		should be given to a transition period after the start of this type of assessment.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	We do agree that given the widespread effects of these facilities above 300 kV that these should be subjected to more rigorous assessments.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	We do agree that given the widespread effects of these facilities above 300 kV that these should be subjected to more rigorous assessments.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	We do agree that given the widespread effects of these facilities above 300 kV that these should be subjected to more rigorous assessments.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: see response for Q20.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment: see response for Q20.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	In the case of generating capacity replacement, some guidance as to allowable system adjustments might be needed for clarification. Is calling on contingency reserves from a Reserve Sharing Group immediately prior to internal redispatch of available resources OK? What about Network Customer generation not at maximum output but available for redispatch ? What about transmission reconfiguration, cutting firm purchases (pro-rata or in entirety) acceptable?
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	N/A
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	See reply to Q26.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	See reply to Q26.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment: Not applicable/

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

[1] System adjustment can be manual or automatic

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Generator protection is designed to trip only those units required. In addition, it is the magnitude of generation tripped rather than the number of units tripped that is of the greatest significance to the stability of the grid.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: Dynamic studies of seasonal load conditions should include the effects of induction motors, and particularly in areas where traditional load models have indicated a problem. Unfortunately, there is a lack of data to support the amount and characteristics of the detailed induction load models in many areas. In addition to the consideration of the dynamic effects of induction motor loads, the effects of static capacitor banks installed at distribution voltage levels would need to be considered as well. Prior to making this a requirement in the reliability standards, the industry needs guidance as to how this data should be developed and maintained for models in future years.

Note that meeting such a requirement would necessitate a significant increase in the dynamic data needed to represent the system. Maintenance of such load model data would require significant resources. Load characteristics valid for a near term model might not be valid for future years. Also, summer peak load, winter peak load, and off-peak load characteristics would differ.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Adjustments that should be allowed are those that can be performed in time to prevent the system from failing to meet performance requirements. These adjustments may include automatic voltage regulator action, governor action, generator runback, and generator tripping.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: The generator runback scheme should complete its action within the time allowed by the emergency ratings of elements that exceed their normal thermal ratings.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: RAS or SPS should meet the same criteria as any protection system.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: The conditions required by SPS standards (PRC).

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☒ No ☐
Comment: Modeling data requirements in R1 applicable to many entities may be either redundant with the MOD submittals or may be conflict for entities that are required to submit this data to Transmission Providers to comply with deadlines in their Tarffs. In addition, data submitted by entities named may be confidential so this issue will have to be addressed among those submitting and receiving needed data.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: Planning Coordinator: The definition of Planning Coordinator should be kept within this document rather than relying on the NERC Functional Model as we believe that this entity has an important role in insuring coordination of transmission and resource plans.

Coordination:
During the teleconference, one issue brought up was the matter of external contingencies being tested as a part of a TP's analysis. The reply was that this issue will be addressed outside this draft standard (TPL-005 and TPL-006) or would be accounted for in the coordination efforts among Transmission Planners. NCEMC is of the opinion that Requirements R5 and R6 need further details to insure adequate anlysis between and among Transmission Planners having varying local planning criteria so that Seams Issues are addressed that are not currently being address in regional and inter-regional studies. To the extent possible, timing of studies should be required to insure coordination between regional and inter-regional groups.

Significant Increase in Study Activity Workload on Transmission Planners:
The increase in both steady state and dynamic studies required to ensure compliance with the proposed standards will result in increased costs and staff additions. The addition of the "Corrective Action Plan" requires the TP to provide a significant amount of documentation for each deficiency identified by the studies. Also, R3.2 requires that the studies simulate the protection scheme for all events. The current software tools cannot automate these studies for bus faults and breaker failure events, requiring each scenario to be studied manually. Additionally, experienced staff capable of performing analyses as described in the proposed standard have become increasingly difficult to find and retain and the talent pool of people with these skills has recently become depleted to alarming levels.

Implementation Plan:
Given the intent of the proposed standard to encourage large scale investment in the EHV system, full implementation will take years, perhaps decades. Acquirement of right-of-way for new EHV lines has become increasingly difficult in recent years and inreasingly expensive. Legal, regulatory, and other difficult issues often take several years to navigate, even for 115kV lines. The Implementation Plan timeframe, if set too short, would be unduly burdensome on Transmission Owners forcing them to be less dicretionary with funds than would be prudent. The proposed implementation plan should include provisions for those cases where viable solutions simply can not be implemented in time due to circumstances beyond the control of Transmission owners. A reasonable period for transition is order.

Design and Construction Constraints:
Even if right-of-way and other legal and regulatory hurdles are cleared, and the capital funding for such a tremendous level of investment was not an issue, the other resources required to actually construct the projects are equally difficult and costly to secure. Raw material prices on comodities like copper and steel have skyrocketed in recent years. Additionally, the skilled labor and Engineering resources are constrained with labor rates almost keeping up with other resource costs. Overall project costs have more than doubled over the last 7-10 years. Recent press releases concerning new generation being planned and then scrapped due to the rapid escalation of project costs are public evidence of this. The inflationary mark-up is impossible to estimate but much less will be built with the same capital investment than is currently envisioned.

Cost-Benefit Analysis:
The proposed standard will be exceedingly expensive to become compliant with unprecedented levels of capital investment in Transmission facilities. Before the standard comes to official vote, it would be prudent for a cost-benefit analysis to be performed to determine if the reliability improvements truly justify the huge expenditures certain under the proposed standard. Additionally, as many jurisdictional rate structures share the cost of such investments between retail and wholesale customers, cost-benefit analyses should be completed for both retail and wholesale customers.

System Adjustment Clarification:
It has already been noted earlier but deserves repeating here: The term "System Adjustment" as outlined in the tables should be better defined. The use of generation for redispatch may have nuances which preclude or otherwise limit their use for studies. Perhaps some clearer guidelines on what is allowed would facilitate transparency and coordination between Transmission Planners.

Transmission Service Evaluation:
A major concern is that the proposed standard appears to be disjointed from the requirements for selling firm Transmission Service. The increase in reliability gained from the proposed standard would, in some regions, quickly be eroded by new firm sales if those sales are based on the historical N-1 ATC requirements. The proposed standard must be applied to long-term firm transmission service requests if Transmission reliability is to be truly enhanced. If the standard is not applied to Transmission Service evaluation, reliability levels for the different classes of firm customers will diverge.

Stakeholder Process:
As a Transmission-Dependent Utility and Network Customer within 3 different Balancing Autorities with one being a Regional Transmission Organization, NCEMC cannot stress

enough the need for a Stakeholder Process for coordination Transmission Planning that may impact Load-Serving Entities and other entities involved. It is critical to address reliability needs of all taking transmission service today and in years to come.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)			
Name:	Denise Roeder		
Organization:	North Carolina Municipal Power Agency 1		
Telephone:	919-760-6255		
E-mail:	droeder@electricities.org		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**	
☐ **ERCOT**	☐	1 — Transmission Owners	
☐ **FRCC**	☐	2 — RTOs and ISOs	
☐ **MRO**	☒	3 — Load-serving Entities	
☐ **NPCC**	☐	4 — Transmission-dependent Utilities	
☐ **RFC**	☐	5 — Electric Generators	
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers	
☐ **SPP**	☐	7 — Large Electricity End Users	
☐ **WECC**	☐	8 — Small Electricity End Users	
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities	
	☐	10 — Regional Reliability Organizations and Regional Entities	

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☐Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☐Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.

- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☐
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☐
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☐
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☐
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment:

[1] System adjustment can be manual or automatic

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment: Much of the language in R1 is redundant, because the MOD standards already address what data are required for modeling purposes. Including data requirements here, as well as in the MOD standards, will introduce the possibility of inconsistencies between the two as well as unnecessary duplication of work for entities providing the data. If any changes need to be made to what data are collected or to whom it is provided, those changes should be made in the MOD standards, not by adding data requirements to this standard.

As for most every standard written, some consideration should be given to the cost of meeting the more stringent requirements proposed for this standard. While it might be possible to make incremental improvements in reliability, it may not be cost-effective, particularly given the low probability of some of the events addressed in the standard. Before stakeholders are asked to vote on this standard, a cost-benefit analysis should be performed to provide what would be an otherwise missing, but very important piece, of information about whether the costs of complying with the requirements of this standard are justified based on the reliability improvements that would be achieved.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Rick White	
Organization:	Northeast Utilities	
Telephone:	860-665-2572	
E-mail:	whitefb@nu.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: There are a few undefined terms in this definition: "Transmission System" and "interconnected Transmission System". The definition needs to specifically identify what should be modeled and in a manner consistent with other NERC definitions. The definition refers to Facility ratings rather than the general reference to FAC-008 & FAC-009**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Modify to "Events which are more severe,but have a lower probability of occurrence, than Planning Events".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☒Do not agree.
Q4. **Comment: "Transmission planning period that covers years six through ten", is sufficient for the standard." Suggest changing the name to Long-Term Planning Assessment.**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: Suggest changing the name to Near-Term Planning Assessment.**	
Q6. **Non-Consequential Load Loss:** Load loss other than	☒Agree.

Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Eliminate "capital" from the definition. It is not defined or consistently applicable to the standard. Reference to vague "other factors, such as asset conditions and age" should be removed from this standard; there are no consistent definitions or industry standards on which to base this requirement, nor does it appear to be a necessary addition to the standard.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Propose, "Events for which Transmission performance requirements must be met".**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: See comment on Q9; proposed modification, "Study of the System or portions of the System to determine whether unit and system angular Stability is maintained, power oscillations are damped, and voltages during the dynamic simulation stay within acceptable perfomance limits.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: Modify to, "The first year that a Tranmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner completes its annual studies."**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement to develop action plans for problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System shall be considered, and documentation with the rationale for the sensitivity testing shall be supplied. The sensitivity case(s) may include one or more of the following conditions:"

2.1.3.3 should refer only to planned facilities that may be delayed. 2.1.3.4 - "variability" is too vague for a standard; the standard needs to be more specific as to the intent. 2.1.3.7 should be consistent with 1.4. These comments also apply to 2.4.3.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement develop action plans for problems highlighted as a result of one of the sensitivities.

Reasonably stressed conditions are dependent upon the study area under review and the standard is not likely to be able to be crafted to provide sufficent and consistent direction. However, it might be helpful if the standard clarified whether the base case should include any unplanned generator outages or whether, aside from potential sensitivities, unplanned generator outages are considered only through P1, P3 or P4 Contingencies. If the standard addresses unplanned generator outages only through P1, P3 and P4, then it is recommended that a mandatory sensitivity analysis, with required mitigation, include various potential combinations of a reasonable amount of unplanned outages. The combinations should be based on the part of the system that is under study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐

Comment: The standard is unclear whether or not it mandates the requirement to devleop action plans for problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System should be considered. Sensitivity case(s) might include among the following conditions:" 2.4.3 should mimic 2.1.3 except in regard to load models.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: There is no need for sensitivity analysis.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: DSM should be included to the extent that its performance is sufficiently and consistently understood. The standard does not use the term "optimal" Therefore, the Drafting Team appears to be interpreting the Standard to require a vertically-integrated Planner to produce a so-called optimal-mix of resources plan. This would be an incorrect assumption and is not required. In areas with independent planners and competitive wholesale markets, it is sufficent to identify system needs and produce a plan that identifies regulated transmission solutions in the event that market-based resources (such as DSM) do not address those identified needs. Therefore, while DSM can be as effective a resource as generation, per Commission Orders,

in areas with ISOs/RTOs and a competitive wholesale market, the NERC Standard cannot prescribe the development so-called optimized (as is suggesgted by the Drafting Team) resource-mix plans, as identified by a central planner.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: The study area should be based upon planning expertise and knowledge of the system, giving due consideration to external impacts.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: They should be viewed differently in the Near-Term. However, these should be defined terms.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: It is unclear as to what the commited project is being removed from. Suggested language "…removed from the plan…".

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Given the low probability of extended overlapping outages of overhead facilities, systems have been designed assuming that load shedding following the loss of a second transmission line is permissible. Eliminating any allowance for load shedding for this condition may require significant system expansion and cost to to customers. However, it would be reasonable to consider establishing an upper bound to the amount of load that could be shed for these purposes.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Should also consider the initial loss of a transformer, followed by the loss of a Transmission circuit. This should state a transformer with a "high-side" rating above 300 kV.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	This should state a transformer with a "high-side" rating above 300 kV.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of 2 additional generators.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a monopolar DC line
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a Transmission circuit
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a transformer

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm

[1] System adjustment can be manual or automatic

transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: This should also apply to firm transfers via single or double ac facilities as well. In either case, the transfer could be linked to dedicated facilities.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Difficult to envision how such an event would occur.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: This requirement is too specific and limited. Induction motors are only one component of a complex load model. Complex load models are not always necessary, nor are they always the most conservative, depending on the analysis that is being conducted. Where complex load models are required, they should be considered; this may involve use of complex motor and lighting loads or polynomial load representations

with or without frequency dependence. This question also suggests the need for an industry standard regarding transient voltage recovery.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Manual or automatic adjustments should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment. Manual system adjustment should be allowed in between the multiple Contingencies described in P5, provided that the adjustment can be made between contingencies using short-term reserves (10-30 minute).

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: Generation runback should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐

Comment: However, this should only be allowed where failure of an automatic runback that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: It is not recommended that an SPS be used in this situation, that over time, the proliferation of SPSs may degrade system reliability and unduly complicate system operations. If allowed an SPS should only be used where the failure of the SPS that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Only allowed where SPS failure would not have significant adverse impact on the Bulk Electric System; non-Consequential loss of load should be allowed up to an amount potentially specified in the standard.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: System must remain stable with acceptable voltages and all equipment within applicable emergency limits.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☒
Comment: Unsure due to ambiguities in the standard. Depending upon the final standard, New England may need exceptions for existing facilities or allowance for a transition period to develop a compliance plan.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: There should be a "P0" standard that applies to system performance without any contingencies.

Standard should be clear that stabiltiy analysis is not required for Long-Term Planning Assessment.

R.1.1 Load forecasts should be addressed in MOD standards, not TPL.

R 1.4 This should only refer to known long-term outages, not planned outages. Delete "including protective relays"; this is addressed through other provisions.

R.2.1 Shorten "Near-Term Transmission Planning Horizon Planning Assessment" to "Near-Term Planning Assessment".

R 2.2 Shorten "Long-Term Transmission Planning Horizon Planning Assessment" to "Long-Term Planning Assessment".

R2.1, 2.2, 2.3 & 2.4 – The initial paragraph should have identical language regarding 'annual', and 'current or past' aspects.

R2.1.1 There should not be a requirement to look at years one and two; a 5 year study should be sufficient. If there has been an ongoing 5 year study, there should be no major unexpected problems occurring in years 1 and 2. Studies of earlier years should only be required if an unanticipated event occurred that had not been considered in prior studies. The TPL should not address shorter term "Operating Studies" or operating issues.

R 2.2.1 Modify to "If any known projects have a lead time that is longer than ten years, the Planning Assessment shall be extended accordingly."

R 2.6 Steady-state, short circuit, and stability analysis should be required no more than every 5 years unless there is a significant change the system.

R 2.6.1 Remove reference to "market structure changes". The purpose of it's inclusion is unclear.

R 2.7.1.1 Project initiation date should be deleted. If it is retainted, it needs to be defined.

R 2.7.3 Committed and Proposed projects should be defined.

R 3.2.1/R 4.3 - What is the intent of this requirement? There should probably be an MOD associated with Generator Owner requirement to provide related generator protection/ limiter data or other plant information.

R 3.4/R 4.5.2 Remove the requirement to implement changes to reduce or mitigate the likelihood of such consequences of Extreme Events. This may not be reasonable or achieveable.

R 3.2 Sectionalizing schemes shall be considered when reflecting the post-contingent system.

R 3.2.2 - Propose deleting this. Line ratings should already take relay loadability into account.

R 3.3.2.1 - Proposed deleting "expected duration". This would be dependent upon the damage to the element due to the iniating event and other factors.

R 3.3.2.2 - The requirements of this section do not match P6.

R 3.3.3 - Change introductory language to read "Those multiple Contingencies that are…"

R 3.5 - Generation tripping should be allowed as well as generation run-back. In addition, all performance requirements shall be met, rather than just meeting facility rating requirements. Suggested lanague "Manual and automatic generation run-back and/or generation tripping is allowed as a response to single and multiple Contingencies as long as the performance requirements of this standard are met." If these changes are accepted, R 3.6 can be deleted.

R 4 and R 4.1 - The language should be made similar to R 3 and R 3.1.

Suggest bringing language similar R4.4 into the R 3, the steady state section.

R 4.2 - High speed automatic reclosing schemes shall be considered.

R 6.3 - Change to read "Planning Coordinators of neighboring impacted areas".

Table 1 3 b and c Extreme Event descriptions are vague concepts that cannot be practically simulated. 3 d and e are not reasonable or practically useful to simulate.

Table 1, P8 - Language needs to be clarifed as to how the 300 kV threshold is to be treated for transformers. Is this for the high side, low side, or both sides? P5 is much clearer.

Table 2 - Clarification needs to be made that the faults being simulated are permanent faults. This can be addressed under the "Performance Requirements" portion at the beginning of the table, or modify each fault description.

Table 2 P9. Recommend that this be changed to require that faults should be on different phases of each of two adjacent transmission circuits on a multiple circuit transmission tower

Table 1, P9(6) and Table 2 P9 - It is unclear as to what is meant by "A spare transformer inserted to replace an outaged transformer followed by System adjustments". Unclear as to what is to be tested.

General comment - Transmission System is used throughout the document and is an undefined term

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)	
Name:	John Leland
Organization:	Northwestern Energy NWMT
Telephone:	406-497-3383
E-mail:	John.Leland@northwestern.com

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment** (check all industry segments in which your company is registered)
☐ ERCOT	☒	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs and ISOs
☐ MRO	☐	3 — Load-serving Entities
☐ NPCC	☐	4 — Transmission-dependent Utilities
☐ RFC	☐	5 — Electric Generators
☐ SERC	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ SPP	☐	7 — Large Electricity End Users
☒ WECC	☐	8 — Small Electricity End Users
☐ NA – Not Applicable	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment: NWE recommends the words "and may include non-firm transactions" after the words "firm transaction obligations".**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☒Do not agree.
Q6. **Comment: Include the words "not directly connected" before period of first sentence; and what does "load loss" mean?**	
Q7. **Planning Assessment:** Documented evaluation of future	☒Agree.

Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Do not agree.
Q7. **Comment: Insert before performance studies the words "current or past that is known to be valid".**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: System stability studies covers this definition.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.

- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: The current list is too prescriptive as many may not apply to a specific TP, yet they would be required to study it.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: Each TP's stressed conditions vary, making a list that is applicable to all will not achieve the desired purpose.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☒
Comment: The TP should have the ability to determine the sensitivity to use.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☒
Comment: However, the TP should have the abiltiy to determine the sensitivity to use.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of

Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒
Comment: The word "including" should be "may include", mandating what should be studied is not appropriate. Also, including DSM in the list presumes the balancing area is deficient in generation, which may not always be the case.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: R2.7.2 does not refer to "how a study area should be determined". This added statement should be eliminated.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: No, there are no clear guidelines on how to make this distinction.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: Same problem as Q18; but it isn't clear what level of documentation is needed.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material

changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: Non-consequential load loss should be permitted for this contingency.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: Non-consequential load loss should be permitted for this contingency.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.

[1] System adjustment can be manual or automatic

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: Plant stability is an artifical distinction and is a subset of transient stability.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☒
Comment: If such a standard is constructed, it should be based on a common mode of failure mechanism.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: All adjustments should be allowed as long as they are realistic and achievable in the time frame required and consistent with other study parameters. Also, if a RAS (or special protection system) is the adjustment and if cascading could result from the event, then redundancy should be required.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Yes, (1) if the failure of the runback scheme results in cascading, then it should not be allowed; (2) the power flow should be within the time-limited equipment ratings; and (3) the frequency should be within allowable limits.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐

Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: RAS or SPS should not be allowed for non three phase single line faults. If cascading could result from the failure of the RAS to operate properly, then redundancy should be required.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: RAS or SPS should meet performance requirements including reserve requirements.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: WECC allows N-1 generator tripping, and the transmission systems have been designed around this criteria. Moving away from this criteria is not necessary, and for critical N-1 events, redundancy is in place.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☒ No ☐
Comment: Eliminating the N-1 RAS in the West could cause problems for utilities in the West with local jurisdictional cost recovery.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☐ No ☒
Comment:

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ ERCOT ☐ FRCC ☐ MRO ☒ NPCC ☐ RFC ☐ SERC ☐ SPP ☐ WECC ☐ NA – Not Applicable	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☒	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: **NPCC RSC, Regional Standards Committee**

Lead Contact: **Guy V. Zito**

Contact Organization: **Northeast Power Coordinating Council**

Contact Segment: **10**

Contact Telephone: **212-840-1070**

Contact E-mail: **gzito@npcc.org**

Additional Member Name	Additional Member Organization	Region*	Segment*
Al Adamson	New York State Reliability Council	**NPCC**	10
David Kiguel	Hydro One Networks	NPCC	1
Donald Nelson	MA Dept of Public Utilities	NPCC	9
Edwin Thompson	ConEd	NPCC	1
Greg Campoli	New York ISO	NPCC	2
Kathleen Goodman	ISO New England	NPCC	2
Michael Gildea	Constellation Energy	NPCC	6
Michael Ranalli	Ngrid US	NPCC	1
Murale Gopinathan	Northeast Utilities	NPCC	1
Ralph Rufrano	New York Power Authority	NPCC	1
Randy MacDonald	New Brunswick System Operator	NPCC	2
Roger Champagne	HydroQuebec TransEnergie	NPCC	1
Biju Gopi	The IESO, Ontario	NPCC	2
Sylvain Clermont	HydroQuebec TransEnergie	NPCC	1
Reza Rizvi	Northeast Power Coordinating Council	NPCC	10
Guy V. Zito	Northeast Power Coordinating Council	NPCC	10

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the

rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: There are a two undefined terms in this definition: "Transmission System" and "interconnected Transmission System". The definition needs to specifically identify what should be modeled applicable to the subject area and in a manner consistent with other NERC definitions. The definition refers to Facility ratings rather than the general reference to FAC-008 & FAC-009**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Modify to "Events which are more severe,but have a lower probability of occurrence, than Planning Events".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	

Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Eliminate "capital" from the definition. It is not defined or consistently applicable to the standard. Reference too vague "other factors, such as asset conditions and age" should be removed from this standard; there are no consistent definitions or industry standards on which to base this requirement, nor does it appear to be a necessary addition to the standard.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Propose, "Events for which Transmission performance requirements must be met".**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: See comment on Q9; proposed modification, "Study of the System or portions of the System to determine whether system angular Stability is maintained, power oscillations are damped, and voltages during the dynamic simulation stay within acceptable perfomance limits even if unit instability exists.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☒Do not agree.
Q11. **Comment: Modify to, "The first year that a Tranmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner**	

completes and communicates its annual studies."

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement to develop action plans in accordance with consequences of problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System shall be considered, and documentation with the rationale for the sensitivity testing shall be supplied. The sensitivity case(s) may include one or more of the following conditions:"

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement to develop action plans in accordance with consequences of problems highlighted as a result of one of the sensitivities.

Reasonably stressed conditions are dependent upon the study area under review and the standard is not likely to be able to be crafted to provide sufficent and consistent direction. However, it might be helpful if the standard clarified whether the base case should include any unplanned generator outages or whether, aside from potential sensitivities, unplanned generator outages are considered only through P1, P3 or P4 Contingencies. If the standard addresses unplanned generator outages only through P1, P3 and P4, then it is recommended that a mandatory sensitivity analysis, with required mitigation, include various potential combinations of a reasonable amount of unplanned outages. The combinations should be based on the part of the system that is under study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment: The standard is unclear whether or not it mandates the requirement to develop action plans in accordance with the consequences of problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System should be considered. Sensitivity case(s) might include among the following conditions:" 2.4.3 shold mimic 2.1.3 except in regard to load models.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: There is no need for sensitivity analysis.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: DSM should be included to the extent that its performance is sufficiently and consistently understood. The standard does not use the term "optimal" Therefore, the Drafting Team appears to be interpreting the Standard to require a vertically-integrated Planner to produce a so-called optimal-mix of resources plan. This would be an incorrect assumption and is not required. In areas with independent planners and competitive wholesale markets, it is sufficent to identify system needs and produce a plan that identifies regulated transmission solutions in the event that market-based resources (such as DSM) do not address those identified needs. Therefore, while DSM can be as effective a resource as generation, per Commission Orders, in areas with ISOs/RTOs and a competitive wholesale market, the NERC Standard cannot prescribe the

development so-called optimized (as is suggested by the Drafting Team) resource-mix plans, as identified by a central planner.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐

Comment: The study area should be based upon planning expertise and knowledge of the system, giving due consideration to external impacts.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐

Comment: They should be viewed differently in the Near-Term.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐

Comment: It is unclear as to what the committed project is being removed from. Suggested language "…removed from the plan…".

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL

standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Given the low probability of extended overlapping outages of overhead facilities, systems have been designed assuming that load shedding following the loss of a second transmission line is permissible. Eliminating any allowance for load shedding for this condition may require significant system expansion and cost to to customers.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐

Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of 2 additional generators.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a monopolar DC line
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a Transmission circuit
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a transformer

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

[1] System adjustment can be manual or automatic

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: This should also apply to firm transfers via single or double ac facilities as well. In either case, the transfer could be linked to dedicated facilities.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☒
Comment: The contingency studied are the same and as a result should be combined into one table.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Difficult to envision how such an event would occur.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: This requirement is too specific and limited. Induction motors are only one component of a complex load model. Complex load models are not always necessary, nor are they always the most conservative, depending on the analysis that is being conducted. Where complex load models are required, they should be considered; this may involve use of complex motor and lighting loads or polynomial load representations with or without frequency dependence. This question also suggests the need for an industry standard regarding transient voltage recovery.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Manual or automatic adjustments should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment. Manual system adjustment should be allowed in between the multiple Contingencies described in P5, provided that the adjustment can be made between contingencies using short-term reserves (10-30 minute).

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: Generation runback should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐

Comment: However, this should only be allowed where failure of an automatic runback that is not functionally redundant would not have significant adverse impact on the Bulk Power System.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐

Comment: A SPS may be used to provide protection for infrequent contingencies, or for temporary conditions that may exist such as project delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages. An SPS may also be applied to preserve system integrity in the event of severe facility outages and extreme contingencies. The decision to employ an SPS shall take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: See response to Q38.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: System must remain stable with acceptable voltages and all equipment within applicable emergency limits.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☒

Comment: Until section R3.6.1 is finalized, we will be unable to determine whether a regional variance is required.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒

Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment:

The SDT has made an effort to define Base Case, yet has not used the term in the standard. At a minimum, Base Case should be referred to in sections 2.1.1, 2.1.2

Standard should be clear that stabiltiy analysis is not required for Long-Term Planning Assessment.

R.1.1 Load forecasts should be addressed in MOD standards, not TPL.

R 1.4 This should only refer to known long-term outages, not planned outages. Delete "including protective relays"; this is addressed through other provisions.

R2.1, 2.2, 2.3 & 2.4 – The initial paragraph should have identical language regarding 'annual', and 'current or past' aspects.

R2.1 There should not be a requirement to look at years one and two; a 5 year study should be sufficient. If there has been an ongoing 5 year study, there should be no major unexpected problems occurring in years 1 and 2. Studies of earlier years should only be required if an unanticipated event occurred that had not been considered in prior studies. The TPL should not address shorter term "Operating Studies" or operating issues.

R 2.2.1 Modify to "If any known projects have a lead time that is longer than ten years, the Planning Assessment shall be extended accordingly."

R 2.6.1 Remove reference to "market structure changes". The purpose of its inclusion is unclear.

R 2.7.1.1 Project initiation date should be deleted. If it is retained, it needs to be defined.

R 3.2.1/R 4.3 - What is the intent of this requirement? There should probably be an MOD associated with Generator Owner requirement to provide related generator protection/ limiter data or other plant information.

R 3.4/R 4.5.2 Remove the requirement to implement changes to reduce or mitigate the likelihood of such consequences of Extreme Events. This may not be reasonable or achieveable.

R 3.2 Sectionalizing schemes shall be considered when reflecting the post-contingent system.

R 3.3.2.1 - Proposed deleting "expected duration". This would be dependent upon the damage to the element due to the iniating event and other factors.

R 3.3.3 - Change introductory language to read "Those multiple Contingencies that are…"

R 3.5 - Generation tripping should be allowed as well as generation run-back. In addition, all performance requirements shall be met, rather than just meeting facility rating requirements. Suggested language "Manual and automatic generation run-back and/or generation tripping is allowed as a response to single and multiple Contingencies as long as the performance requirements of this standard are met." If these changes are accepted, R 3.6 can be deleted.

R 4 and R 4.1 - The language should be made similar to R 3 and R 3.1.

Suggest bringing language similar R4.4 into the R 3, the steady state section.

R 4.2 - High speed automatic reclosing schemes shall be considered.

R 6.2 - Change to read "Transmission Planners of neighboring areas".

Table 1 3 b and c Extreme Event descriptions are vague concepts that cannot be practically simulated. 3 d and e are not reasonable or practically useful to simulate.

Table 1, P8 - Language needs to be clarifed as to how the 300 kV threshold is to be treated for transformers. Is this for the high side, low side, or both sides? P5 is much clearer.

Table 2 P9. Recommend that this be changed to require that faults should be on different phases of each of two adjacent transmission circuits on a multiple circuit transmission tower

Table 1, P9(6) and Table 2 P9 - It is unclear as to what is meant by "A spare transformer inserted to replace an outaged transformer followed by System adjustments". Unclear as to what is to be tested.

General comment - Transmission System is used throughout the document and is an undefined term, both "Transmission" and "System" are defined NERC terms. We recommend that the SDT use the term "System" to replace "Transmission System". System is defined as "A combination of generation, transmission, and distribution components".

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

<table>
<tr><th colspan="3">Individual Commenter Information
(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td>Name:</td><td colspan="2">Gregory Sullivan</td></tr>
<tr><td>Organization:</td><td colspan="2">NSTAR Electric and Gas Corporation</td></tr>
<tr><td>Telephone:</td><td colspan="2">781-441-8515</td></tr>
<tr><td>E-mail:</td><td colspan="2">gregory.sullivan @nstar.com</td></tr>
<tr><td>NERC Region (check all Regions in which your company operates)</td><td></td><td>Registered Ballot Body Segment (check all industry segments in which your company is registered)</td></tr>
<tr><td rowspan="10">☐ ERCOT
☐ FRCC
☐ MRO
☒ NPCC
☐ RFC
☐ SERC
☐ SPP
☐ WECC
☐ NA – Not Applicable</td><td>☒</td><td>1 — Transmission Owners</td></tr>
<tr><td>☐</td><td>2 — RTOs and ISOs</td></tr>
<tr><td>☒</td><td>3 — Load-serving Entities</td></tr>
<tr><td>☐</td><td>4 — Transmission-dependent Utilities</td></tr>
<tr><td>☐</td><td>5 — Electric Generators</td></tr>
<tr><td>☐</td><td>6 — Electricity Brokers, Aggregators, and Marketers</td></tr>
<tr><td>☐</td><td>7 — Large Electricity End Users</td></tr>
<tr><td>☐</td><td>8 — Small Electricity End Users</td></tr>
<tr><td>☐</td><td>9 — Federal, State, Provincial Regulatory or other Government Entities</td></tr>
<tr><td>☐</td><td>10 — Regional Reliability Organizations and Regional Entities</td></tr>
</table>

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: There are a few undefined terms in this definition: "Transmission System" and "interconnected Transmission System". The definition needs to specifically identify what should be modeled and in a manner consistent with other NERC definitions. The definition refers to Facility ratings rather than the general reference to FAC-008 & FAC-009**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Modify to "Events which are more severe,but have a lower probability of occurrence, than Planning Events".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☒Do not agree.
Q4. **Comment: "Transmission planning period that covers years six through ten", is sufficient for the standard." Suggest changing the name to Long-Term Planning Assessment.**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: Suggest changing the name to Near-Term Planning Assessment.**	
Q6. **Non-Consequential Load Loss:** Load loss other than	☒Agree.

Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Eliminate "capital" from the definition. It is not defined or consistently applicable to the standard. Reference to vague "other factors, such as asset conditions and age" should be removed from this standard; there are no consistent definitions or industry standards on which to base this requirement, nor does it appear to be a necessary addition to the standard.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Propose, "Events for which Transmission performance requirements must be met".**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: See comment on Q9; proposed modification, "Study of the System or portions of the System to determine whether unit and system angular Stability is maintained, power oscillations are damped, and voltages during the dynamic simulation stay within acceptable perfomance limits.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: Modify to, "The first year that a Tranmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner completes its annual studies."**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement to develop action plans for problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System shall be considered, and documentation with the rationale for the sensitivity testing shall be supplied. The sensitivity case(s) may include one or more of the following conditions:"

2.1.3.3 should refer only to planned facilities that may be delayed. 2.1.3.4 - "variability" is too vague for a standard; the standard needs to be more specific as to the intent. 2.1.3.7 should be consistent with 1.4. These comments also apply to 2.4.3.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement develop action plans for problems highlighted as a result of one of the sensitivities.

Reasonably stressed conditions are dependent upon the study area under review and the standard is not likely to be able to be crafted to provide sufficent and consistent direction. However, it might be helpful if the standard clarified whether the base case should include any unplanned generator outages or whether, aside from potential sensitivities, unplanned generator outages are considered only through P1, P3 or P4 Contingencies. If the standard addresses unplanned generator outages only through P1, P3 and P4, then it is recommended that a mandatory sensitivity analysis, with required mitigation, include various potential combinations of a reasonable amount of unplanned outages. The combinations should be based on the part of the system that is under study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment: The standard is unclear whether or not it mandates the requirement to devleop action plans for problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System should be considered. Sensitivity case(s) might include among the following conditions:" 2.4.3 shold mimic 2.1.3 except in regard to load models.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: There is no need for sensitivity analysis.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: DSM should be included to the extent that its performance is sufficiently and consistently understood. The standard does not use the term "optimal" Therefore, the Drafting Team appears to be interpreting the Standard to require a vertically-integrated Planner to produce a so-called optimal-mix of resources plan. This would be an incorrect assumption and is not required. In areas with independent planners and competitive wholesale markets, it is sufficent to identify system needs and produce a plan that identifies regulated transmission solutions in the event that market-based resources (such as DSM) do not address those identified needs. Therefore, while DSM can be as effective a resource as generation, per Commission Orders,

in areas with ISOs/RTOs and a competitive wholesale market, the NERC Standard cannot prescribe the development so-called optimized (as is suggesgted by the Drafting Team) resource-mix plans, as identified by a central planner.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐

Comment: The study area should be based upon planning expertise and knowledge of the system, giving due consideration to external impacts.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐

Comment: They should be viewed differently in the Near-Term. However, these should be defined terms.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐

Comment: It is unclear as to what the commited project is being removed from. Suggested language "…removed from the plan…".

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Given the low probability of extended overlapping outages of overhead facilities, systems have been designed assuming that load shedding following the loss of a second transmission line is permissible. Eliminating any allowance for load shedding for this condition may require significant system expansion and cost to to customers. However, it would be reasonable to consider establishing an upper bound to the amount of load that could be shed for these purposes.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Should also consider the initial loss of a transformer, followed by the loss of a Transmission circuit. This should state a transformer with a "high-side" rating above 300 kV.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	This should state a transformer with a "high-side" rating above 300 kV.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of 2 additional generators.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a monopolar DC line
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a Transmission circuit
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a transformer

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm

[1] System adjustment can be manual or automatic

transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: This should also apply to firm transfers via single or double ac facilities as well. In either case, the transfer could be linked to dedicated facilities.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Difficult to envision how such an event would occur.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: This requirement is too specific and limited. Induction motors are only one component of a complex load model. Complex load models are not always necessary, nor are they always the most conservative, depending on the analysis that is being conducted. Where complex load models are required, they should be considered; this may involve use of complex motor and lighting loads or polynomial load representations

with or without frequency dependence. This question also suggests the need for an industry standard regarding transient voltage recovery.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Manual or automatic adjustments should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment. Manual system adjustment should be allowed in between the multiple Contingencies described in P5, provided that the adjustment can be made between contingencies using short-term reserves (10-30 minute).

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: Generation runback should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐

Comment: However, this should only be allowed where failure of an automatic runback that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: Only allowed where the failure of an SPS that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Only allowed where SPS failure would not have significant adverse impact on the Bulk Electric System; non-Consequential loss of load should be allowed up to an amount potentially specified in the standard.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: System must remain stable with acceptable voltages and all equipment within applicable emergency limits.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☒
Comment: Unsure due to ambiguities in the standard. Depending upon the final standard, New England may need exceptions for existing facilities or allowance for a transition period to develop a compliance plan.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: There should be a "P0" standard that applies to system performance without any contingencies.

Standard should be clear that stabiltiy analysis is not required for Long-Term Planning Assessment.

R.1.1 Load forecasts should be addressed in MOD standards, not TPL.

R 1.4 This should only refer to known long-term outages, not planned outages. Delete "including protective relays"; this is addressed through other provisions.

R.2.1 Shorten "Near-Term Transmission Planning Horizon Planning Assessment" to "Near-Term Planning Assessment".

R 2.2 Shorten "Long-Term Transmission Planning Horizon Planning Assessment" to "Long-Term Planning Assessment".

R2.1, 2.2, 2.3 & 2.4 – The initial paragraph should have identical language regarding 'annual', and 'current or past' aspects.

R2.1.1 There should not be a requirement to look at years one and two; a 5 year study should be sufficient. If there has been an ongoing 5 year study, there should be no major unexpected problems occurring in years 1 and 2. Studies of earlier years should only be required if an unanticipated event occurred that had not been considered in prior studies. The TPL should not address shorter term "Operating Studies" or operating issues.

R 2.2.1 Modify to "If any known projects have a lead time that is longer than ten years, the Planning Assessment shall be extended accordingly."

R 2.6 Steady-state, short circuit, and stability analysis should be required no more than every 5 years unless there is a significant change the system.

R 2.6.1 Remove reference to "market structure changes". The purpose of it's inclusion is unclear.

R 2.7.1.1 Project initiation date should be deleted. If it is retainted, it needs to be defined.

R 2.7.3 Committed and Proposed projects should be defined.

R 3.2.1/R 4.3 - What is the intent of this requirement? There should probably be an MOD associated with Generator Owner requirement to provide related generator protection/ limiter data or other plant information.

R 3.4/R 4.5.2 Remove the requirement to implement changes to reduce or mitigate the likelihood of such consequences of Extreme Events. This may not be reasonable or achieveable.

R 3.2 Sectionalizing schemes shall be considered when reflecting the post-contingent system.

R 3.2.2 - Propose deleting this. Line ratings should already take relay loadability into account.

R 3.3.2.1 - Proposed deleting "expected duration". This would be dependent upon the damage to the element due to the iniating event and other factors.

R 3.3.2.2 - The requirements of this section do not match P6.

R 3.3.3 - Change introductory language to read "Those multiple Contingencies that are…"

R 3.5 - Generation tripping should be allowed as well as generation run-back. In addition, all performance requirements shall be met, rather than just meeting facility rating requirements. Suggested lanague "Manual and automatic generation run-back and/or generation tripping is allowed as a response to single and multiple Contingencies as long as the performance requirements of this standard are met." If these changes are accepted, R 3.6 can be deleted.

R 4 and R 4.1 - The language should be made similar to R 3 and R 3.1.

Suggest bringing language similar R4.4 into the R 3, the steady state section.

R 4.2 - High speed automatic reclosing schemes shall be considered.

R 6.3 - Change to read "Planning Coordinators of neighboring impacted areas".

Table 1 3 b and c Extreme Event descriptions are vague concepts that cannot be practically simulated. 3 d and e are not reasonable or practically useful to simulate.

Table 1, P8 - Language needs to be clarifed as to how the 300 kV threshold is to be treated for transformers. Is this for the high side, low side, or both sides? P5 is much clearer.

Table 2 - Clarification needs to be made that the faults being simulated are permanent faults. This can be addressed under the "Performance Requirements" portion at the beginning of the table, or modify each fault description.

Table 2 P9. Recommend that this be changed to require that faults should be on different phases of each of two adjacent transmission circuits on a multiple circuit transmission tower

Table 1, P9(6) and Table 2 P9 - It is unclear as to what is meant by "A spare transformer inserted to replace an outaged transformer followed by System adjustments". Unclear as to what is to be tested.

General comment - Transmission System is used throughout the document and is an undefined term

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

<table>
<tr><th colspan="3">Individual Commenter Information
(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td>Name:</td><td colspan="2">John Mayhan</td></tr>
<tr><td>Organization:</td><td colspan="2">Omaha Public Power District</td></tr>
<tr><td>Telephone:</td><td colspan="2">(402) 552-5173</td></tr>
<tr><td>E-mail:</td><td colspan="2">jmayhan@oppd.com</td></tr>
<tr><td>NERC Region (check all Regions in which your company operates)</td><td></td><td>Registered Ballot Body Segment (check all industry segments in which your company is registered)</td></tr>
<tr><td rowspan="10">☐ ERCOT
☐ FRCC
☒ MRO
☐ NPCC
☐ RFC
☐ SERC
☐ SPP
☐ WECC
☐ NA – Not Applicable</td><td>☒</td><td>1 — Transmission Owners</td></tr>
<tr><td>☐</td><td>2 — RTOs and ISOs</td></tr>
<tr><td>☒</td><td>3 — Load-serving Entities</td></tr>
<tr><td>☐</td><td>4 — Transmission-dependent Utilities</td></tr>
<tr><td>☐</td><td>5 — Electric Generators</td></tr>
<tr><td>☒</td><td>6 — Electricity Brokers, Aggregators, and Marketers</td></tr>
<tr><td>☐</td><td>7 — Large Electricity End Users</td></tr>
<tr><td>☐</td><td>8 — Small Electricity End Users</td></tr>
<tr><td>☐</td><td>9 — Federal, State, Provincial Regulatory or other Government Entities</td></tr>
<tr><td>☐</td><td>10 — Regional Reliability Organizations and Regional Entities</td></tr>
</table>

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☐Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☐Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.

- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☐
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☐
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☐
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☐
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment:

[1] System adjustment can be manual or automatic

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment: The terms Bus Tie Breaker and Non-Bus Tie Breaker used in Tables 1 and 2 are not well defined. To prevent misinterpretation of the standard, include diagrams that point out examples of bus tie breakers and non-bus tie breakers for each of the following bus schemes: 1) Single bus 2) Ring bus 3) Breaker and a half 4) Double bus double breaker.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **[Due Date in bold]**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☒ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☒	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: PJM Planning

Lead Contact: Ganesh Velummylum

Contact Organization: PJM

Contact Segment: RTO / ISO

Contact Telephone: 610-666-4307

Contact E-mail: velumg@pjm.com

Additional Member Name	Additional Member Organization	Region*	Segment*
Mark Kuras		RFC	2
Mahendra Patel		RFC	2
Paul McGlynn		RFC	2
Mohamed Osman		RFC	2
Chuck Liebold		RFC	2
Leanne Harrison		RFC	2
Susan McGill		RFC	2

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. The SDT has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the SDT are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890 and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The SDT did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. The SDT organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The SDT determined that the requirements and analysis for Steady State are different from those for stability. As such, the SDT separated the analysis requirements and created two performance requirement tables.

The SDT recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The SDT has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The SDT has not addressed Measures, Risk Factors, Violation Severity Factors or Time Horizons at this time. These will be addressed when the SDT has better defined the requirements of the standard.

For questions where you agree with the SDT, please state that you agree and if available, please provide supporting documentation. If you disagree with the SDT, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you

believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the SDT would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the SDT is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☒Do not agree.
Q1. **Comment:** **Also FAC-010**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☒Do not agree.
Q2. **Comment:** **Need to tighten definition example- load that trips in sympathy with fault (motor trips as a direct result but not in protection zone)**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☒Do not agree.
Q3. **Comment: Agree with concept but need better definition**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers Years One through five.	☒Agree. ☒Do not agree.
Q5. **Comment:** **Near Term should cover years two through five. Planning should not study year one because Operation Planning does and one year is too short of a period to mitigate**	

on a permanent basis.	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☒Do not agree.
Q6. **Comment: Non-Consequential Load Loss should not include load loss due to manual, UVLS and UFLS.**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☐Do not agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☒Do not agree.
Q10. **Comment: Does "inter-area oscillations are damped" imply that you also have to do frequency domain analysis? (Because some industry experts would claim that without small signal analysis you cannot ensure that inter-area oscillations are damped.)**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions", FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The SDT has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☒ No ☒
Comment: **At the least, it should provide a measure that indicates that you meet the requirement. Need to modify 2.4.3 to specify what if any performance requirement need to be met.**

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☒ No ☒
Comment: **Again, 'reasonable' is a very subjective term. Refer to comments on question 12**

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☒
Comment: **Yes, however, clear direction is needed. Specific wording that defines if you have done enough, and met the compliance requirements.**

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year 6 and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☒
Comment: **PJM agrees that no sensitivity analysis is required for long term period**

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If Yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☒

Comment: **Yes- DSM should be modeled consistent with how it is expected to be operated based on contractual/operating relationships.**

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☒

Comment: **Yes – At a minimum the system conditions and / or contingency that identified the system deficiency should be evaluated to determine that it has corrected the issue. The extent of the study area needs to be consistent with the size / complexity of the corrective action plan.**

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☒
Comment: **We agree that there needs to be a differentiation between committed and proposed projects. Proposed projects, particularly generation interconnections and their associated network upgrades need to be identified as a group so that they can be removed from cases if the proposed generation interconnection does not move forward.**

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable BES that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the SDT attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The SDT is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the SDT to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL Standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	**Should be a 3 phase fault not a single line to ground fault.**
Q21. P5-1: For facilities	☒Agree.	

above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: Agree with performance requirement

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards - P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: yes

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

[1] System adjustment can be manual or automatic

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No☐
Comment: **Yes, but should model the true clearing times of each individual unit. Also the standard should clearly state that system reinforcement should not be required for this extreme events.**

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: **No. This is good in theory but is impractical to implement with the large interconnected systems that span large geographical areas.**

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: **Adjustments should be allowed consistent the time periods being studied.**

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control.

The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment: Yes

,
Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☒
Comment. **Yes- At a minimum the emergency rating needs to be coordinated with the SPS timing.**

The SDT has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: Yes.

- Delayed clearing due to primary relay system communication failure
- Bus Contingencies should not be included for sensitivity/stressed case
- Sensitivity case should not be included for long term study
- Need to clearly define number of studies required for Load Flow/Stability and what performance criteria must be met.
    - Peak Case
    - Off Peak
    - Sensitivity

- Need to allow SPS operation after a first contingency, system readjustment and a “second “ first contingency.
- SPSs can include generation tripping

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	John Collins	
Organization:	Platte River Power Authority	
Telephone:	970-229-5272	
E-mail:	collinsj@prpa.org	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☐Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☐Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.

- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☐
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☐
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☐
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☐
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21^{st} Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment:

[1] System adjustment can be manual or automatic

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment: 1) P5 and P8 in Tables 1 and 2 – If you keep the "300 kV bar" for distinction between P5 and P8, then please make an exception for P5 to be "Yes" on Non-Consequential Load Loss where load pockets (a.k.a. local load-serving areas) are concerned because "system adjustments" might not be possible to avoid the need for Non-Consequential Load Loss after the loss of another line into the load pocket.

Example - A city, which is a type of load pocket, is served by three transmission lines. If one of the lines into the city is removed from service for maintenance, "system adjustments" within the city might not be possible to prevent steady-state voltages from dropping below an acceptable limit after loss of a second line into the city. If during such an "N-1Line-N1Line" Planning Event the city voltages become extremely low, then shedding of some of the city's load should be allowed, i.e. Non-Consequential Load Loss, for all voltages 100 kV and above. In this example, when one line into the city is removed from service, the TOP could either arm an SPS or RAS for automatic load shedding, or alert the operators to possible implementation of an Operating Procedure for manual load shedding. The city, along with its TO and other authorities, may decide by their own wishes to "raise the bar" and add facilities to maintain acceptable voltages for the worst "N-1Line-1Line" affecting only its local area. However, a facility addition type of solution, driven by a "No" for Non-Consequential Load Loss in P5, should not be mandated.

"Controlled interruption of electric supply to customers (load shedding)" should be allowed for all voltages 100 kV and above as Footnote (c) in TPL-003 allows. Consistent with this request to allow load shedding for this type of disturbance for all voltages 100 kV and above, FERC Order No. 693 in Paragraph 1825 regarding TPL-003 for Category C disturbances (including "N-1Line-1Line") does not ask for "controlled load interruption" to be eliminated, but rather FERC directed the ERO to modify footnote (c) to Table 1 to clarify the term "controlled load interruption". And please note FAC-010-1, R2.5 – "Planned or controlled interruption…(load shedding)…" for TPL-003 conflicts with "No" for Non-Consequential Load Loss in P5 of Draft TPL.

2) Proposed revision to R3.5 – "Manual and automatic generation runback and generator tripping are allowed as a response to single and multiple contingencies as long as Facility Ratings are not exceeded and the result of the generator action, such as location and ramp-up speed of the AGC unit(s) responding to the generation trip or runback, loss of reactive resource, impact on reserves, and restart time of tripped unit(s), meets the performance requirements."

Planning and Operations need flexibility to coordinate with the requirements of Engineering who established the Facility Ratings. It should not matter which method of generation redispatch is employed if all impacts of tripping vs. running back a generator are properly considered and performance requirements are met. The time period for a particular Emergency Rating might require faster generation redispatch than a runback or set of runbacks are capable of providing. Therefore, it may be necessary to trip one 100 MW unit rather than runback several units for a total of 100 MW.

No need for R3.6 with above revision to R3.5.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Mark Byrd	
Organization:	Progress Energy Carolinas	
Telephone:	919-546-7937	
E-mail:	mark.byrd@pgnmail.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☒ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)			
Group Name:			
Lead Contact:			
Contact Organization:			
Contact Segment:			
Contact Telephone:			
Contact E-mail:			
Additional Member Name	**Additional Member Organization**	**Region***	**Segment***

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☒Agree. ☒Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment: Planning assessments should not include asset conditions and age.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Don't need to differentiate between plant and system. These are not usually separated. It would be better to separate angular stability and voltage stability. They are studied independently.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: Don't need to differentiate between plant and system. These are not usually separated. It would be better to separate angular stability and voltage stability. They are studied independently.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii “Sensitivity studies and critical system conditions” FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: This should be system specific.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: This should be system specific.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: Sensitivities should not be required for Long-Term.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: State regulatory requirements mandate that we consider DSM alternatives. The DSM contracts would have to adequately support the intended use.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: There are separate regional processes for coordination with neighboring utilities.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: Are projects are proposed until they are completed.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: We always should be able to show that we meet performance requirements.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☒Agree. ☐Do not agree.	It is absolutely necessary, however, to allow interruption of firm transfers as a System adjustment. To do otherwise would cause extremely large expenditures for very low probability independent events.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	It is absolutely necessary, however, to allow interruption of firm transfers as a System adjustment. To do otherwise would cause extremely large expenditures for very low probability independent events.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Agree. ☐Do not agree.	It is absolutely necessary, however, to allow interruption of firm transfers as a System adjustment. To do otherwise would cause extremely large expenditures for very low probability independent events.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance

requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: This is a very low probability multiple contingency and would cost an extreme sum of money to remedy. Need to clarify whether or not the stuck breaker was connected with loss of element.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒
Comment: DC and AC lines should be treated comparably.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of

[1] System adjustment can be manual or automatic

Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: Don't need to differentiate between plant and system. These are not usually separated. It would be better to separate angular stability and voltage stability. They are studied independently

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: This needs to be done but we currently don't have sufficient data and tools to properly perform the analysis. More interconnection-wide testing and data collection needs to be performed. We will need to transition into these studies over time.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Both manual and automatic adjustments should be allowed.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: If the rating is a 2 hour rating then the adjustment should be complete within 2 hours.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment:

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒

Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:

1. In R4.6 and other locations, the generator exemption of 20 MW should be increased to 75 MVA.

2. Need to define bus-tie breaker. Is center breaker in a breaker and a half scheme a bus-tie breaker?

3. Need to continue to allow interruptions to firm transfers. This is essentially allowing redispatch and is an economically sensible solution to low probability high impact multiple contingencies.

4. Need to clarify if the "stuck breaker" is associated with the first event in multiple event contingencies or does one have to choose a breaker not involved with the first event. Note that a breaker cannot be "stuck" if there is no demand to trip. Therefore, a stuck breaker that is not adjacent to the first event will not have a demand to trip.

5. Need to distinguish what the difference is between a "stuck breaker" and a "[loss of breaker due to] internal fault". The specific meaning could make the difference in the clearing time selected for stability studies (normal clearing time versus delayed clearing time).

6. In the Table 2 (for stability) the last bullet under Planning events says to "simulate normal clearing times unless otherwise specified". Does this mean that "stuck breaker" events should be simulated with normal clearing times? Note that in the real world, internally faulted breakers may clear in either normal or delayed clearing time, depending on the relaying and CT configuration.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**	
Name:	Bart White
Organization:	Progress Energy Florida, Inc. (PEF)
Telephone:	727-344-4352
E-mail:	bart.white@pgnmail.com

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ ERCOT ☒ FRCC ☐ MRO ☐ NPCC ☐ RFC ☐ SERC ☐ SPP ☐ WECC ☐ NA – Not Applicable	☒	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☒	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☒	5 — Electric Generators
	☒	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☒Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii “Sensitivity studies and critical system conditions” FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.

- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: PEF concurs with the draft standard's approach with regard to Q15 that sensitivities should not be required for years six through ten.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: The use of DSM, whether exclusively or in conjunction with other measures, is an acceptable operating procedure for use in a Corrective Action Plan, as long as the Transmission Owner demonstrates availability and accuracy of DSM data and its viability as an operating procedure for each applicable scenario.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒

Comment: Each Corrective Action Plan as stated in the original assessments should be trusted as effective, provided the Transmission Owner can demonstrate with its own internal assessments the effectiveness of each Corrective Action Plan.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒

Comment: This differentiation is meaningless when modeling projects in cases for planning analysis. The standard should instead set criteria for when models can be relied upon for planning purposes such that changes to the future plan will not have an impact on reliability.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐

Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	This single contingency event has a very low probability of occurrence, and thus a more stringent performance requirement than currently exists is not warranted.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration. Furthermore, the greater-than-300 kV Bulk Electric System has been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis, placing particular importance on confining the event to a single area (i.e., not resulting in a cascading outage). Past assessments as well as actual events have demonstrated that by not allowing loss of non-consequential load, the Bulk Electric System may actually remain in a less secure state or condition, i.e. in more danger of experiencing cascading outages.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration. Furthermore, the greater-than-300 kV Bulk Electric System has been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis, placing particular

		importance on confining the event to a single area (i.e., not resulting in a cascading outage). Past assessments as well as actual events have demonstrated that by not allowing loss of non-consequential load, the Bulk Electric System may actually remain in a less secure state or condition, i.e. in more danger of experiencing cascading outages.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration. Furthermore, the greater-than-300 kV Bulk Electric System has been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis, placing particular importance on confining the event to a single area (i.e., not resulting in a cascading outage). Past assessments as well as actual events have demonstrated that by not allowing loss of non-consequential load, the Bulk Electric System may actually remain in a less secure state or condition, i.e. in more danger of experiencing cascading outages.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒

Comment: This single contingency event has a very low probability of occurrence, and thus a more stringent performance requirement than currently exists is not warranted.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration. Furthermore, the greater-than-300 kV Bulk Electric System has been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis, placing particular importance on confining the event to a single area (i.e., not resulting in a cascading outage). Past assessments as well as actual events have demonstrated that by not allowing loss of non-consequential load, the Bulk Electric System may actually remain in a less secure state or condition, i.e. in more danger of experiencing cascading outages. In addition, it should be noted that the technical specifications of this category contain a major oversight. This new Category P3-1 is essentially a replacement for the existing Categories C5-9, except that the only protection element failure being considered is the failure of a circuit breaker to open. This definition eliminates the need to examine failure of the relay to operate, which in many cases has a more serious impact on grid reliability.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration. Specifically, the sudden loss of a large generator followed soon thereafter by the loss of a second generator would often result in such a large generation-to-load mismatch that Non-Consequential Loss of Load would be inevitable. It is clear, however, that the Bulk Electric System should be planned such that any generator can be maintained (offline) and the system can be operated to the contingency of another generator. This is accomplished in the Security Constrained unit commitment process. However, if the intent of this requirement is that the system should be planned such that there can be no Non-Consequential Load Loss for the loss of a second generator (after System adjustment), then the requirement is too stringent in that the planner would essentially have to plan for 3 generator contingencies. Finally, the probability of an event should not

[1] System adjustment can be manual or automatic

		be the primary factor determining whether or not Non-Consequential Loss of Load is permitted, but rather the presence or absence of cascading for the event.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration, provided that the Non-Consequential Loss of Load is confined to a single control area (i.e., not resulting in a cascading outage). Furthermore, the frequency of an event should not be the primary factor determining whether or not Non-Consequential Loss of Load is permitted, but rather the presence or absence of cascading for the event. Existing Category C requirements are adequate for this type of event.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration, provided that the Non-Consequential Loss of Load is confined to a single control area (i.e., not resulting in a cascading outage). Furthermore, the frequency of an event should not be the primary factor determining whether or not Non-Consequential Loss of Load is permitted, but rather the presence or absence of cascading for the event. Existing Category C requirements are adequate for this type of event.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration, provided that the Non-Consequential Loss of Load is confined to a single control area (i.e., not resulting in a cascading outage). Furthermore, the frequency of an event should not be the primary factor determining whether or not Non-Consequential Loss of Load is permitted, but rather the presence or absence of cascading for the event. Existing Category C requirements are

		adequate for this type of event.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒

Comment: The proposed standard does not distinguish between asynchronous DC ties and the more common parallel connected DC tie. With an asynchronous DC tie, the transfer is lost with the tie. With a parallel DC tie, the transfer will be shifted to the parallel AC system and should have the same performance requirements.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☒

Comment: The separation of steady state and dynamic response analysis requirements into two tables (with different contingencies) is unnecessary, and is inferior to the analysis requirements outlined in Table 1 of the existing TPL Standard. The structure of the existing Table 1 reinforces the requirement for grid stability and maintaining the grid within applicable limits for Category B and C contingencies. Dynamic simulations of Category B and C contingencies that demonstrate grid stability should be followed up with post transient power flow analysis to assess voltage and thermal limits.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒

Comment: There should be no such distinction. All stability studies must meet the Performance Requirements for “Planning Events in Table 2 - Stability Performance”. If there were different Performance Requirements then the distinction may be warranted. If the format for “Planning Events in Table 2 - Stability Performance” remains in its existing state, however, system stability studies are sufficient and performing studies under the guise of Plant Stability would constitute additional work with no incremental benefit.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment: Analysis of this condition should not be required in stability analysis of extreme events due to the fact that no stability simulation (e.g., SLG or 3-phase faults) can be conceived for the Bulk Electric System that would result in simulataneous tripping of all units at a plant.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒

Comment: Requiring detailed modeling of every induction motor on the Bulk Electric System for stability analysis is onerous. Specifically, obtaining a complete set of data for existing induction motors would be infeasible, as would tracking future installations of induction motors. The benefits of such an effort are significantly outweighed by the logistical difficulties. To address the technical merits, the modeling of the delayed voltage recovery response that has been observed in some large urban areas during periods of high air conditioning usage is considerably more complex than can be addressed by simply representing induction motor effects. The scope of the delayed voltage recovery issue is extremely limited and its effect on the grid is generally self correcting due to automatic disconnection of the affected air conditioners. Requirements for specific types of load models are not appropriate in the TPL standard.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Provided events are confined to a single area (i.e., no cascading outages), manual and automatic adjustment (increase or decrease) of Var output and manual and automatic tripping or reduction of overall output of generators should be allowed.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Provided events are confined to a single area (i.e., no cascading outages), automatic runback of generators should be allowed.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: This requirement is addressed in PRC-005 and these requirements should not be addressed again in this Standard. However, the use of RAS or SPS should be allowed as necessary for any single contingency event, provided that such use does not result in cascading outages. It should be noted that the performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. Revision of the existing TPL standards will require updating of the contingency references in PRC-012-0.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: The use of RAS or SPS should be allowed as necessary for any single contingency event, provided that such use does not result in cascading outages. It should be noted that the performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. Revision of the existing TPL standards will require updating of the contingency references in PRC-012-0.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: The use of RAS or SPS should be allowed as necessary for any single contingency event, provided that such use does not result in cascading outages. It should be noted that the performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. Revision of the existing TPL standards will require updating of the contingency references in PRC-012-0.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment: No, but PEF reserves the right to apply for variances based on the completed version of this or any other standard.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: General Comments

NERC Standards TPL 001-0 through TPL 004-0 are approved standards that only required modifications pursuant to FERC Order 693. In this proposed draft standard TPL 001-1, the Standard Drafting Team (SDT) has far exceeded the recommendations suggested by FERC in the Order and has created unnecessary confusion. We disagree with the SDT's decision to combine NERC Standards TPL 001-0 through TPL 004-0 into one standard. Some changes to the existing TPL Standards may be warranted. One particular improvement would be clarifying the tables such that the table for TPL-001, for example, would only contain the performance criteria for Category A, with footnotes only applicable to that category, clarified as directed by FERC in Order 693. Similarly, TPL-002 would only contain performance criteria for Category B, and so on.

In addition to combining the standards, the SDT has significantly changed contingency specifications and required performance levels. In many cases the changes represent a very significant increase in required performance standards that will result in the following:

a) major capital expenditures, some of which will be of a magnitude unprecedented for the Bulk Electric System. Many of these projects would be constructed to mitigate one single low-probability event. The ratepayers, upon discovery of this necessity and realization that these significant expenditures will be passed on to them in their rates, will certainly object to these efforts and will question the wisdom of NERC's mandating change on such a massive scale without the knowledge or input of the public. The SDT stated in its continent-wide conference call on October 10, 2007 that the intent of many of the objectives contained in the proposed TPL-001-1 was to "raise the bar" for electric utilities. We would like to know specifically what this means. The phrase "raise the bar" is vague and overused in North American vernacular in general, and it is particularly irresponsible to use such vagaries when proposing standards which will result in unaffordable upgrades to the North American Bulk Electric System.

b) reductions in ATC. To be compliant with the more stringent requirements of TPL-001-1, Transmission Operators would in many cases be forced to reduce ATC in order to decrease transmission flows to a point at which corrective actions may be taken without the result of cascading. This is diametrically in opposition to one of the key objectives of deregulation and comparable treatment for all entities engaged in transactions on the Bulk Electric System.

c) Reduced Reliability. The elimination of footnote (b) will result in many outage scenarios for which loss of Non Consequential Load is presently unavoidable, but subsequently prohibited. For some scenarios, Transmission Owners may seek to avoid the excessive cost of a project by simply removing breakers from substations, thereby increasing the range of the initial breaker-to-breaker operation and essentially converting the disallowed Non Consequential Load to Consequential Load. This is obviously an undesirable option and in opposition to fundamental principles of reliability, but might be rendered necessary due to the increased requirements of TPL-001-1.

d) Inability to react to issues of non-compliance. The dynamic nature of planning analysis is such that, from one annual planning cycle to the next, the constantly changing load and generation forecasts invariably result in emerging transmission projects unforeseen in previous cycles. With the increased stringency of TPL-001-1, reacting to these emerging needs in time to demonstrate compliance will be impossible, and thus non-compliance is seen as an inevitability. To further clarify, the major transmission projects that TPL-001-1 would necessitate would be of a magnitude such that extensive engineering, land acquisition and involvement with regulatory and governmental agencies would be required, which could result in project lead times of 10 years or more. Not only would a lengthy transition period be needed for TPL-001-1, but upon the Standard’s effective date the ability to implement all future projects would need to be given special consideration in light of these challenges.

In other cases, the performance criteria are not clearly defined, such as the timing between multiple contingencies, and the level of readiness of the system before and after Planning Events.

Finally, the SDT has chosen to eliminate the footnotes in the current standards, contrary to the direction of FERC in Order 693 to “clarify” the footnotes. The purpose of the footnotes is to further explain terms in the tables, provide guidance in interpreting the expected performance criteria, and specify any exceptions to the criteria. Footnotes also serve the purpose of keeping the standard concise by eliminating repetitiveness.

Specific comments on the Draft Standard

Performance Criteria
The performance requirements table should clearly define what the initial state of the system is assumed to be before any Planning Events, and what the state of the system is assumed to be after the Planning Event. For example, P1 (single contingency) events: assuming that the system is to be compliant, the state of the system prior to the event must be “secure” such that the event could occur and there is no interruption of firm transfer or loss of load, Equipment Ratings are not exceeded, System steady state voltages and post-transient voltage deviation are within acceptable limits. However, the system is not as it was before the event. The system could be described as “normal” but perhaps not “secure”. If the requirement is that the system must also be “secure” after the event, then the standard must clarify what is allowed for “system adjustments” after the first Planning event to prepare for the next. FERC Order 693 directed the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency. However, in order to bring the system to a secure state, as is necessary for the second contingency of a category C3 or C5 event, footnote (c) allows curtailment of firm transfers, and FERC Order 693 only required footnote (c) to be clarify the term “controlled load interruption”, leaving the curtailment language intact. The implication of this interpretation is critical to peninsular Florida. The Category B loss of one 500 kV line from Florida to Georgia is sustainable, such that the system is “normal” after the event. However, in order to be

prepared for the next contingency, (the loss of the second 500 kV line), firm transfers must be curtailed (Interruption of Firm Transfer). Without the ability to curtail firm transfers, a “super-firm” priority of transmission service is created for non-native load customers, and thus comparable treatment no longer exists.

Comments on New Performance Tables:
The draft TPL standard represents a major change in the Table 1 contingency definitions and required performance levels.

Table 1 Contingencies C1 and C2 are being moved to the single contingency category. While C1 and C2 represent single element outages, their probability of occurrence is much lower than the other Category B contingencies and they do not belong in the single contingency performance requirements group.

Footnote (b) which permits, as a limited exception in unique circumstances with a sound rational basis, some localized load reduction for single contingencies, has been removed. This is a very significant change for some utilities. Footnote (c) which permits load shedding and curtailment of firm transfers has been removed from C1, C2 and most of C3. This is a very significant increase in required performance level that is not justified.

The "applicable rating" for loading and voltages in Table 1 has been removed so that essentially, the same ratings and voltage restrictions apply to both B and C contingencies. Some utilities plan to a normal rating for single contingencies but will allow a higher short term rating for Category C events. This practice appears to be either disallowed or inadequately described in TPL-001-1. Transmission Owners should allowed to base ratings on manufacturer specifications or other reasonable criteria using sound engineering judgment.

Several new Category D "extreme events" have been added which greatly expand the scope and complexity of Category D studies. These are (1) any two unrelated single element outages and (2) wide area events a. through h. These represent a major increase in the scope of Category D studies and probably a doubling of required SWG studies.
It should be note that the existing Categories D1 through D4 have been substantially changed to eliminate analysis of relay failure contingencies. The philosophy contained in the existing TPL-004 standard is that faults with a protection failure should be evaluated whether that failure is a circuit breaker, relay or CT; the proposed standard restricts the analysis to breaker failure.

300 kV Threshold Performance Level
The TPL-001-1 draft sets a threshold of higher performance to facilities above 300 kV than previously established in the existing standard. We do not agree that such a threshold is necessary or warranted. Requirements which are more stringent for these facilities may wrongly influence decisions on project alternatives in favor of facilities with less stringent requirements. Additionally, facilities above 300 kV naturally tend to transport larger amounts of power. The loss of single or multiple facilities above 300 kV generally results in an immediate generation-to-load mismatch too great to avoid either curtailment of firm transactions or loss of Non Consequential Load, or both. Singling out facilities above 300 kV for more stringent requirements is therefore clearly unreasonable.

DC Line Performance Requirement

The TPL-001-1 draft sets a lower performance requirement for the loss of a single pole of a DC line than in the existing standard by allowing interruption of firm transfer if the transfer is deemed to be dependent on the outaged line. Firm transfers are also dependent upon AC lines. The proposed standard does not distinguish between asynchronous DC ties and the more common parallel connected DC tie. With an asynchronous DC tie, the transfer is lost with the tie. With a parallel DC tie, the transfer will be shifted to the parallel AC system and should have the same performance requirements. We do not agree that such an exception for DC lines is necessary or warranted. The decision in selecting DC vs. AC in transmission lines has traditionally been based on the break-even cost and performance of the two alternatives. The lower performance requirement may wrongly influence decisions on project alternatives in favor of DC facilities with less stringent requirements.

Distinction Between Committed and Proposed Projects:
Models cannot discern the difference between a "committed" project, and a "proposed" project in a performance analysis. The standard should instead set criteria for when models can be relied upon for planning purposes such that changes to the future plan will not have an impact on reliability. The intent of Requirements R2.7.3 and R2.7.4 should be combined and added into R2.7.1.1. Rather than adding the additional requirement to document a criteria, the requirement should be that in the Near-Term Planning Horizon, projects cannot be removed (or modified) without demonstrating that the revised plan meets performance criteria. In addition, the requirement in R2.7.1.1 to supply a "project initiation date" is ambiguous. What will constitute "project initiation" …construction start date? …Engineering complete date? …Land procurement date? Funds allocated date (budgeted)? Suggested wording for R2.7.1.1. "Transmission and generation improvement projects for the Near-Term Transmission Planning Horizon, shall have in-service dates provided, and shall not have in-service dates changed, or be removed from planning models, without documentation to show that the revised plan meets performance requirements."

Load Modeling Requirements:
The proposed TPL Standard contains numerous references to load modeling. The goal of improving and verifying the load model is worthwhile but is not appropriate for the TPL standards. Assessment of load model accuracy is best accomplished through detailed analysis of grid disturbance events. The main difficulties in accomplishing this are (1) grid events that significant reduce transmission voltages throughout a load area are infrequently occurring and (2) the process of recreating the event through simulation studies is extremely complex and time consuming. While these efforts should be encouraged they should remain a RRO prerogative. A few concerns not previously addressed by comments to Questions 1-42 include the following:

R1.1.1 Use of expected Load mix - based on the actual or expected aggregate mix of industrial, commercial, and residential Loads. – This requirement is not justified as the load model may be developed through disturbance analysis rather than load type synthesis by customer class. Some Load Serving Entities may have great difficulty in creating load forecasts based on customer class. Load forecasting requirements are adequately addressed in the existing MOD standards and do not belong in the proposed TPL standard.

R1.2. Load models with supporting rationale - that include power factor data that may be based on historical System performance, validated by measurement during stressed

System conditions, or documented Transmission planning area requirements. This requirement is not appropriate for the TPL standards.

R.3.3.2.1. Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment. – this Requirement in its present wording could be construed to mean that the precise amount of load between breakers should be specified and reevaluated with every assessment. This would unnecessary and burdensome, and we therefore seek clarification of this Requirement or its removal altogether.

Requirements for studies using Sensitivity cases: R2.4.3 appears to place equal importance on base cases and sensitivity cases with regard to the need to implement projects or Corrective Action Plans. Terms in TPL-001-1 using forms of the word "sensitivity" need to be clearly defined by the SDT. Additionally, the SDT needs to clarify its intent regarding required action based on results from sensitivity studies. We do not agree that results from sensitivity studies should be given equal standing with results from base scenarios, and we would particularly object to any insinuation that projects would need to be implemented to mitigate violations seen in a sensitivity involving speculative non-firm transfers.

Short Circuit Requirements: The new TPL standard also contains numerous references to short circuit analysis, which are new requirements that expand the TPL standards, but without specific testing or performance criteria. Evidence that short circuit studies have been performed is currently required in the existing FAC-002-0 Standard. Since the primary concern is the appropriate sizing of equipment and the prevention of equipment damage as opposed to overall grid reliability, we do not see the need for a set of requirements within the proposed TPL standard for short circuit studies.

FRCC Specifics: One final specific issue concerns the topography and performance history of the Bulk Electric System in our particular region (FRCC). The FRCC system is a peninsular system having only one interface with the rest of the interconnected NERC system, and has historically demonstrated exceptionally high reliability with no events in recent history cascading beyond the FRCC system. While other areas of the NERC system may require some increased stringency in the TPL standards, PE feels that the adequacy of the existing TPL standards as they apply to the FRCC System has been extensively documented.

Conclusion

In conclusion, we believe that TPL-001-1 is unnecessary and burdensome. In particular, the elimination of footnote (b) will deny Transmission Owners and Transmission Operators the right to curtail Non Consequential Load in order to restore the Bulk Electric System. This elimination has absolutely nothing to do with the reliability of the Bulk Electric System; rather, it places the reduction of Customer Minutes of Interruption (CMI) ahead of reliability. Essentially, the emphasis of TPL-001-1 is inappropriately placed on the reliability of distribution feeders rather than the reliability of the Bulk Electric System. The fundamental objective of the existing TPL Standards has been to protect the reliability of the Bulk Electric System, and we believe all future TPL Standards should do the same.

Given the aforementioned issues, we believe the proposed TPL standard is inferior to the existing Board approved TPL Standards, creates unnecessary confusion, and will require many iterations of industry comment and revision. As an intermediate approach, we would strongly urge the Standard Drafting Team that the existing TPL standards be modified to respond to FERC Order 693 directives, clarify any ambiguities, and that the proposed new standard not be pursued any further.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Jeffrey Mitchell	
Organization:	ReliabilityFirst Corp.	
Telephone:	(330) 247-3043	
E-mail:	jeff.mitchell@rfirst.org	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☒ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☒	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)			
Group Name:			
Lead Contact:			
Contact Organization:			
Contact Segment:			
Contact Telephone:			
Contact E-mail:			
Additional Member Name	**Additional Member Organization**	**Region***	**Segment***

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: To add clarity, the terms "power flow" and "dyanamic" should be included in the definition above. It seems that the defintion may be more detailed than needed without these two terms.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: Should the above definition contain a statement that the load is not intentionally lost, since non-consequential load loss is intentional?**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.

Q6. **Comment: Recommend adding that this load loss is "intentional".**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Recommend adding power flow and dynamic analyses to this definition. Short circuit analyses should not be included.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: I don't believe that this is really the definition of "planning events". This defintion should describe generally what the planning events are, not that they must meet performance requirements.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☒ No ☐
Comment: A minimum of at least one or two that contain certain scenarios chosen from the list should be required.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: A list of suggestions is sufficient. The flexibility to use different stresses on different systems is needed.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☐
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: The study area should be determined by the Transmission Planner and Planning Coordinator.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☐Do not agree.	
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☐Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐

Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

[1] System adjustment can be manual or automatic

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☐ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☐ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☐ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: The requirements for the use of SPS and RAS should be contained in a separate standard. That standard should dictate when the RAS and SPS can be used. The planning studies would then simulate those conditions.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment:

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☐ No ☐
Comment: The requirement for short circuit studies (mentioned in R2 and included in all of R2.3) should be removed from this standard. Relay and protection engineers use a different type of software (Aspen and CAPE) for different reasons (to calculate phase and ground faults and perform relay coordination studies). Those types of studies should not be included in this standard and are totally separate from performing power flow and dynamics studies.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Jonathan Sykes	
Organization:	SRP	
Telephone:	602-236-6442	
E-mail:	jonathan.sykes@srpnet.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☒ **WECC** ☐ **NA – Not Applicable**	☒	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)			
Group Name:			
Lead Contact:			
Contact Organization:			
Contact Segment:			
Contact Telephone:			
Contact E-mail:			
Additional Member Name	**Additional Member Organization**	**Region***	**Segment***

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment: Reword to: Transmission planning period that covers years six or beyond.**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☐Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that	☐Agree.

cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Do not agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.

- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☐
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☐
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☐

Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☐
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☐

Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	The time to adjust the system needs to be provided (when does a N-1-1 become a N-2?). If the cause of the outage is transient (temporary) the operator needs some time to test and restore the element (could be minutes up to several hours). If the element is lost indefinitly, the operator will need some minimum time to adjust the system. If this time is not available prior to the next N-1 then the standard should allow Non-Consequetial Loss of Load.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	same as Q21
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	same as Q21

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance

requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	The time to adjust the system needs to be provided (when does a N-1-1 become a N-2?). If the cause of the outage is transient (temporary) the operator needs some time to test and restore the element (could be minutes up to several hours). If the element is lost indefinitly, the operator will need some minimum time to adjust the system. If this time is not available prior to the next N-1 then the standard should allow Non-Consequetial Loss of Load. Some distinction needs to be made the amount of generation connected at a single point on the BES. a wind farm might have many small generators connected to the BES with an aggregate total of 300Mw or more. This requirement will should only apply to generating sources that might be connected to the BES through a single transformer (i.e. wind farm) with minimum agregate total of 300MW (for N-1).
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	same as Q26.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission	☐Agree. ☒Do not agree.	same as Q26.

[1] System adjustment can be manual or automatic

circuit		
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	same as Q26.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load

model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: The loss of transmission line (N-1) may require Gen drop to prevent instability or violation. Studies will need to be performed that study the congestion of generation and transmission cooridors and loss of various elements.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: As long as Non-Consequential Loss of Load is not a solution for single contingencies (N-1).

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Non-Consequential Loss of Load should not be allowed for single contingencies (N-1) and the system must remain stable with no violations.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: Non-Consequential Loss of Load should not be allowed for single contingencies (N-1) and the system must remain stable with no violations.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: The SDT should be commended for very good work at identifying many different issues of the TPL standards. However, TPL-001-1 should take into account the consequences of a Security-Based or Dependability-Based Misoperation (and failure) of the Protection System.

1) A Security-Based Misoperation of the Protection System may remove additional elements of the BES and could be listed in the table under "multiple contingency".

2) A Dependability-Based Misoperation (or Failure) of a non-redundant Protection System could cause long time delays in clearing faults and clear a large area of BES around the faulted Element. This type of failure may not provide local tripping or breaker failure initiation and remote Protection Systems would need to operate to isolate

the fault or disturbance. Often the operation of the remote Protection Systems would cause long time delays in isolating faults and disturbances.

a) The BES should be studied and those elements need to be identified where Dependability-Based Misoperations (or failures) would prevent meeting the performance requirements of Table 1 (Steady State) or Table 2 (Stability). This type of Misoperation (or Failure) will have to be included in the Tables.

For example, some parts of the BES may be able to survive long time delayed clearing of faults caused by Dependability-Based Protection System Misoperations (or failures) and still meet the performance requirements of the tables. But other parts of the BES may experience cascading outages for this same scenario. One solution to minimize the consequences of Dependability-Based Misoperations (or failures) is to install redundant Protection Systems. The redundant Protection Systems would reduce the possibility of a single Dependability-Based Misoperation (or failure) from affecting the isolation of faults and disturbances.

In addition, the TPL-001 standard will need definitions of Security-Based Misoperation and Dependability-Based Misoperation. The following definitions are used for PRC-004-WECC-1:

Security-Based Misoperation: The incorrect operation of a Protection System or RAS for faults or disturbances outside the intended zone of protection. Security is a component of reliability and is the measure of a device's certainty not to operate falsely.

Dependability-Based Misoperation: Any of the following:

☐ The absence of a Protection System or RAS operation when intended

☐ A Protection System or RAS equipment failure is alarmed or indicated to operating personnel.

☐ A Protection System or RAS equipment failure is discovered.

Dependability is a component of reliability and is the measure of a device's certainty to operate when required.

PROTECTION SYSTEM MISOPERATIONS

Operational Scenario

Security-Based Misoperation
Dependability-Based Misoperation
Breaker Fail

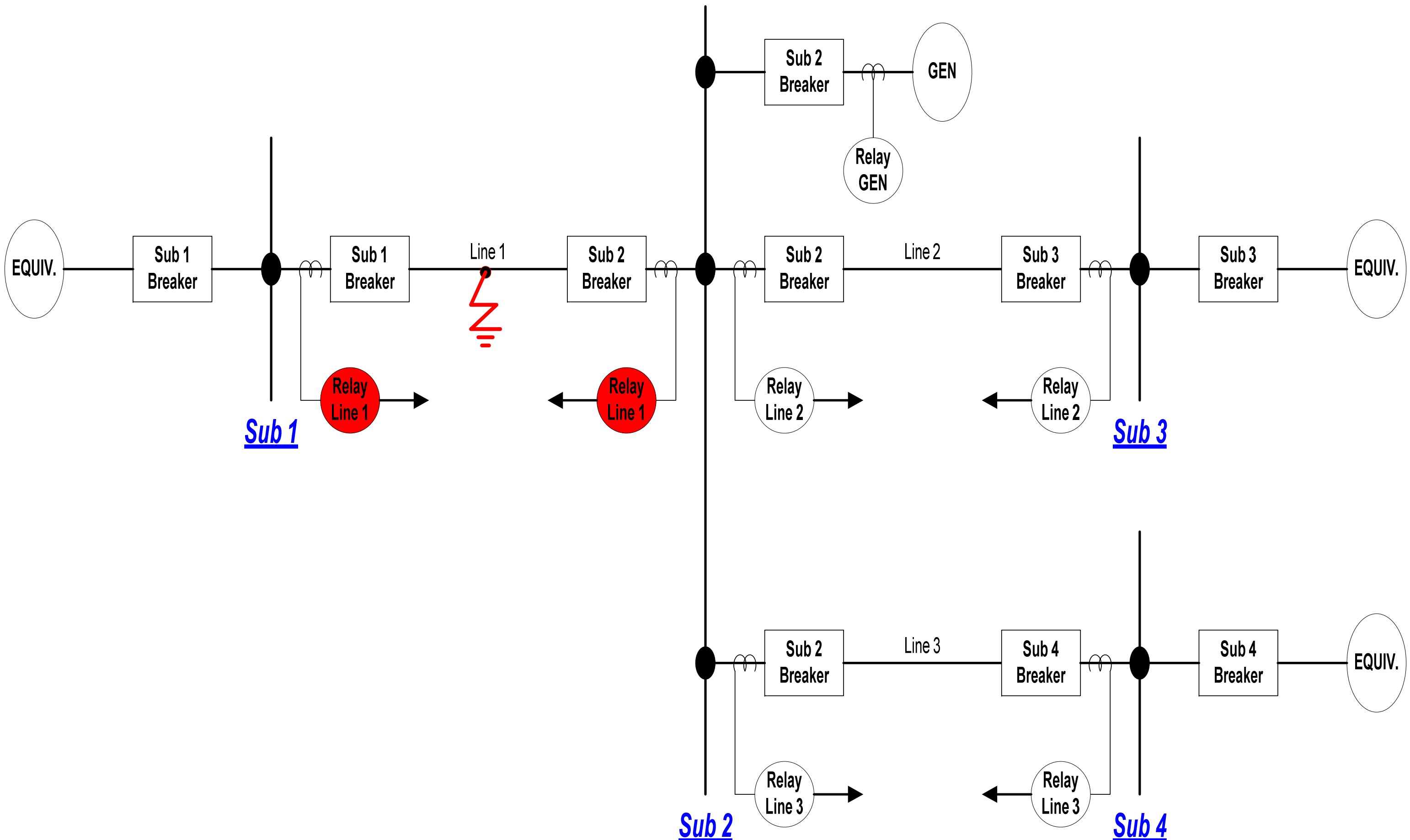
Jonathan Sykes

SALT RIVER PROJECT

10/04/07

CASE 1 – Security-Based Misoperation of the Protection System

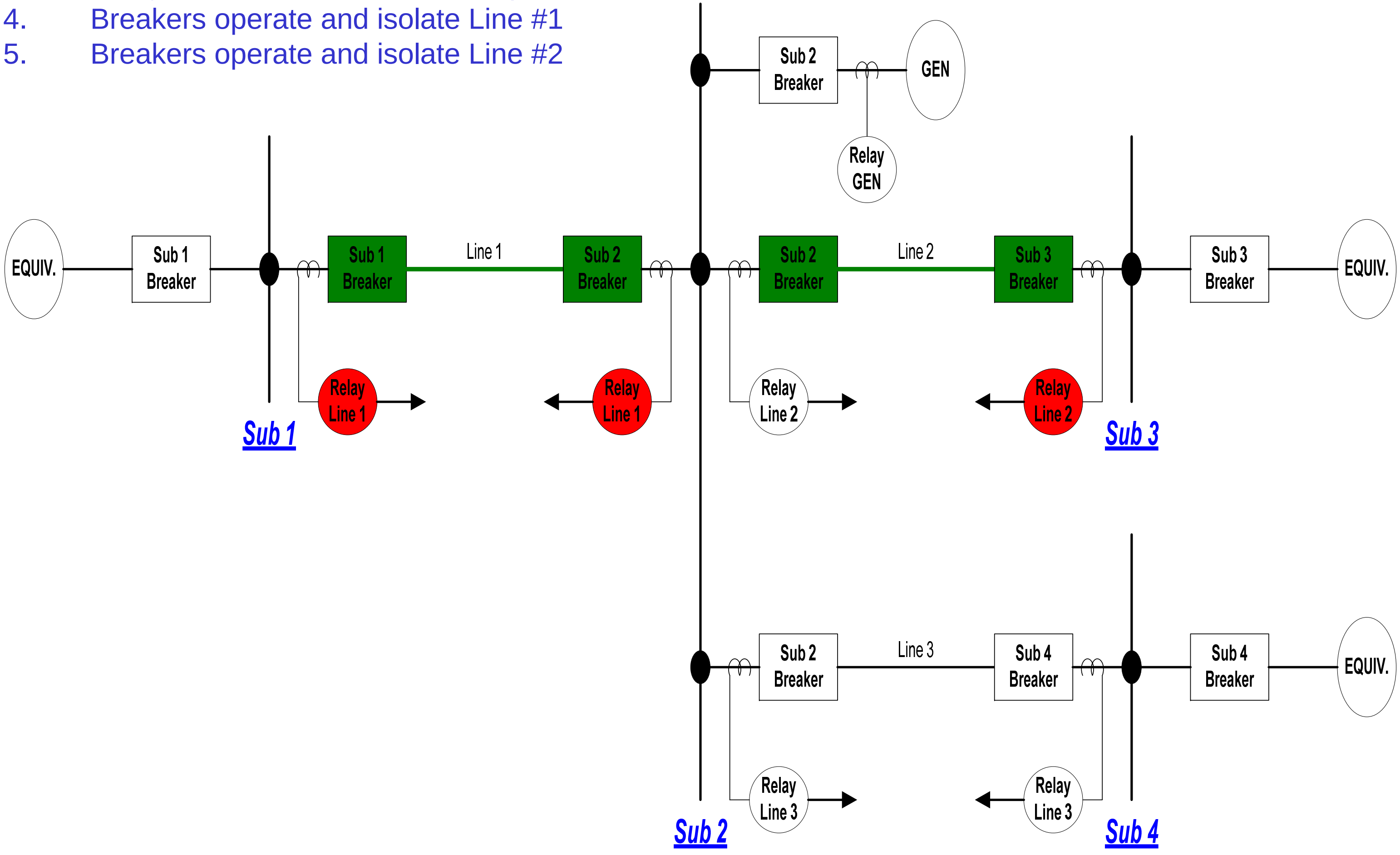
1. Fault Occurs on Line #1
2. Relays on Line #1 Operate



Simplified System One Line

CASE 1 – Security-Based Misoperation of the Protection System

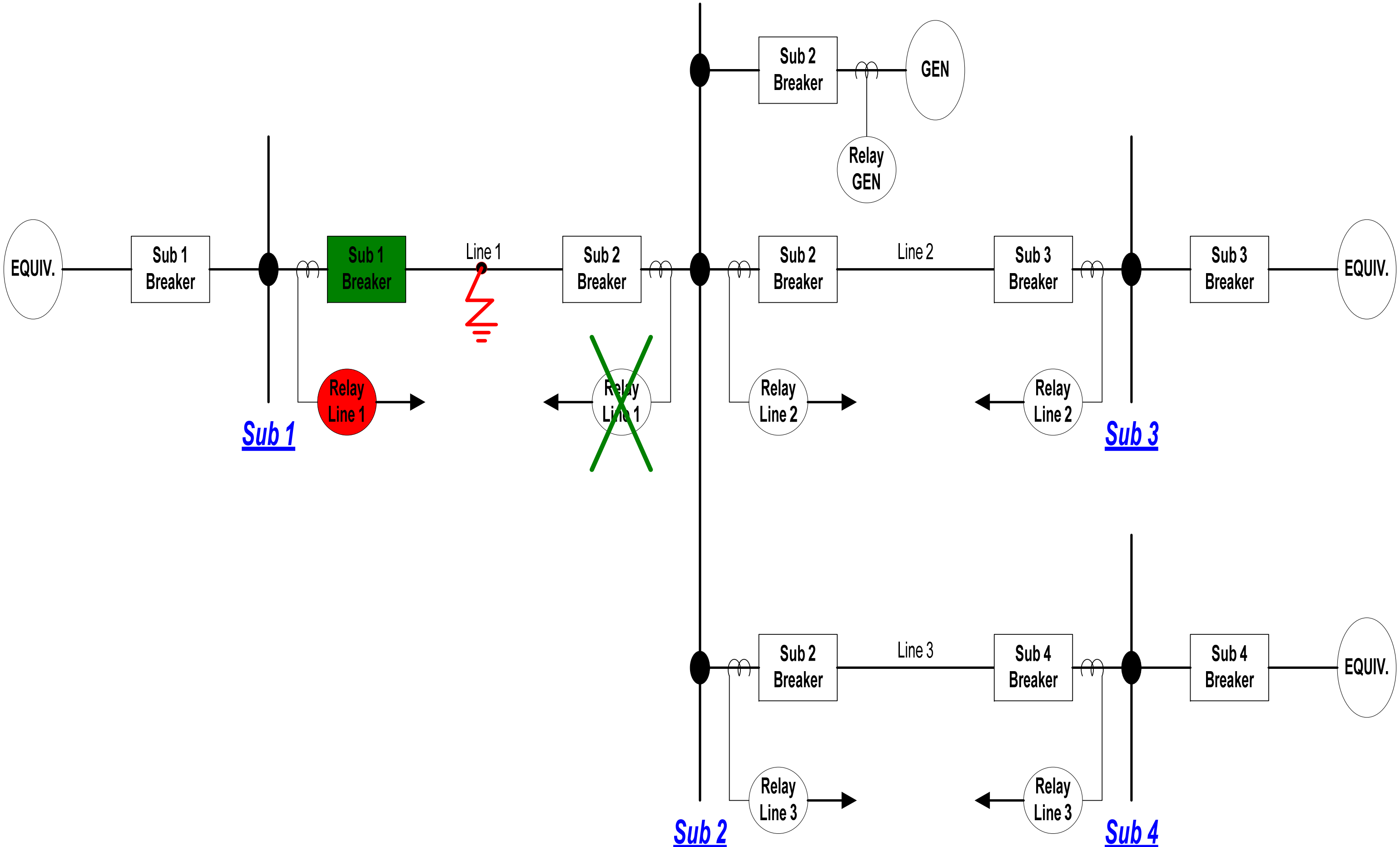
1. Fault Occurs on Line #1
2. Relays on Line #1 Operate
3. Relay at Sub #3 on Line #2 Misoperates
4. Breakers operate and isolate Line #1
5. Breakers operate and isolate Line #2



Simplified System One Line

CASE 2 – Dependability-Based Misoperation of the Protection System

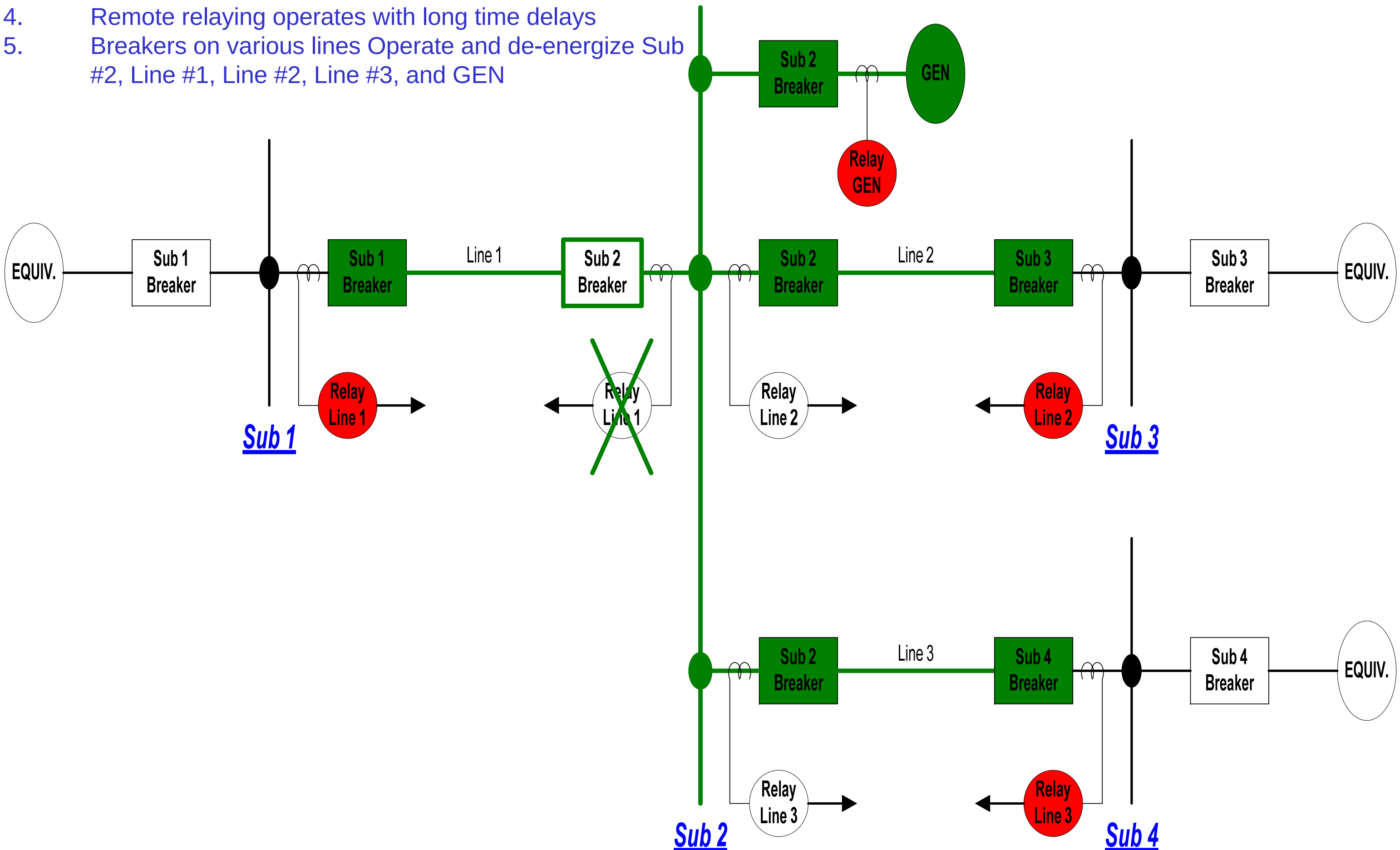
1. Fault Occurs on Line #1
2. Relays at Sub #1 Operate and Open Breaker at Sub #1
3. Relays at Sub #2 **DO NOT** Operate and **DO NOT** initiate Breaker Fail



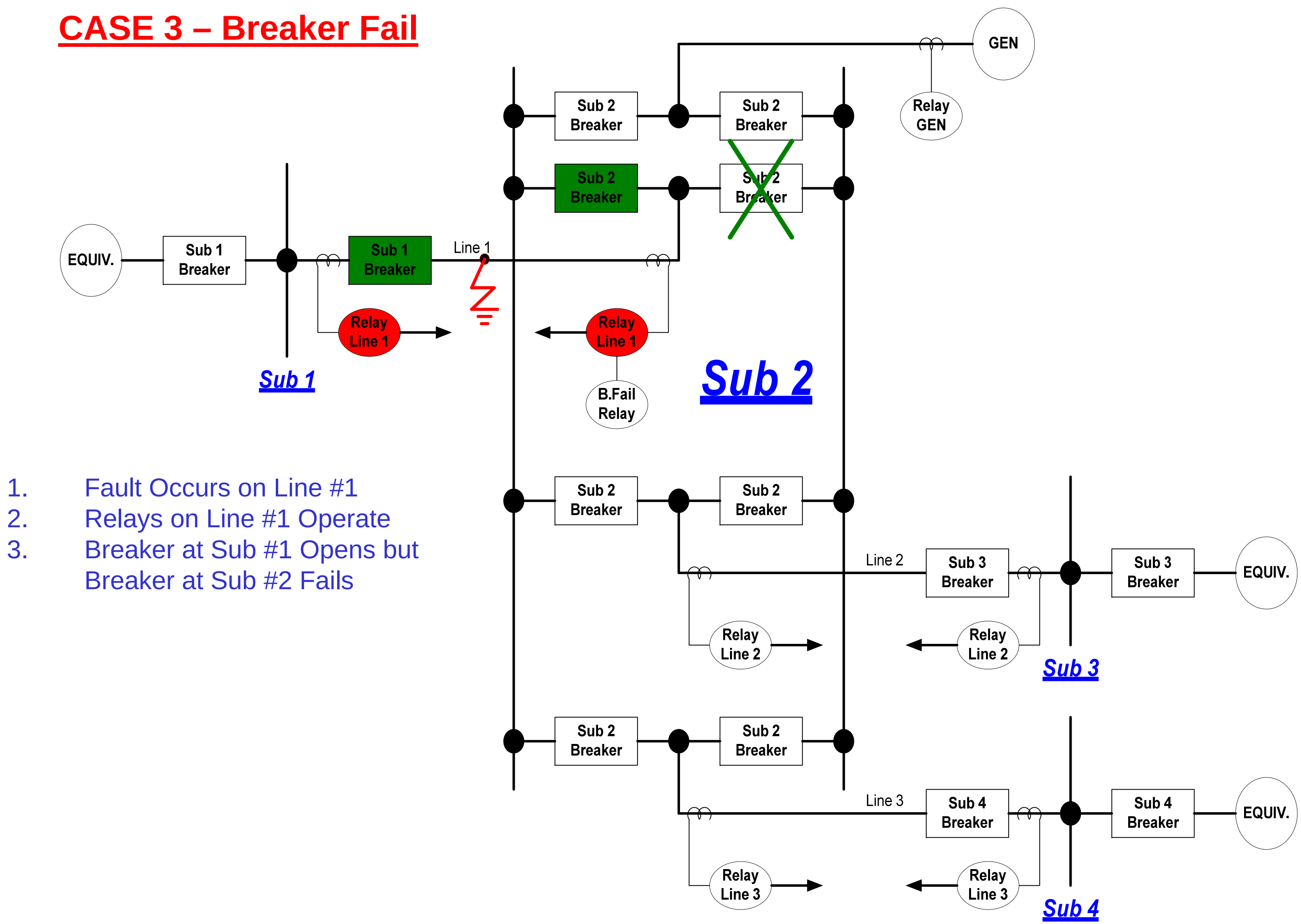
Simplified System One Line

CASE 2 – Dependability-Based Misoperation of the Protection System

1. Fault Occurs on Line #1
2. Relays at Sub #1 Operate and Open Breaker at Sub #1
3. Relays at Sub #2 **DO NOT** Operate and **DO NOT** initiate Breaker Fail
4. Remote relaying operates with long time delays
5. Breakers on various lines Operate and de-energize Sub #2, Line #1, Line #2, Line #3, and GEN



Simplified System One Line

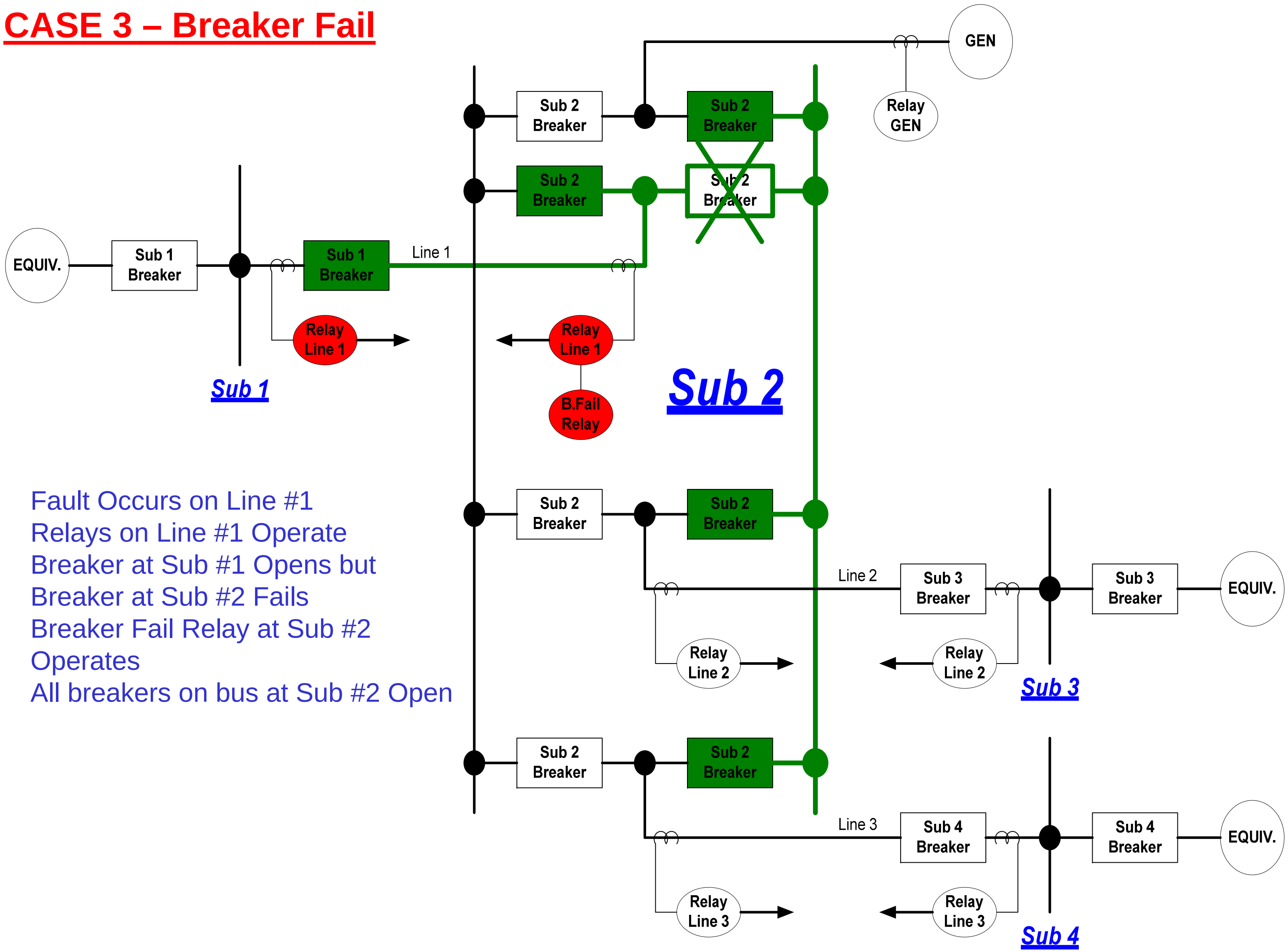


1. Fault Occurs on Line #1
2. Relays on Line #1 Operate
3. Breaker at Sub #1 Opens but Breaker at Sub #2 Fails

Simplified System One Line

(Note: Sub #2 has more detail)

CASE 3 – Breaker Fail



1. Fault Occurs on Line #1
2. Relays on Line #1 Operate
3. Breaker at Sub #1 Opens but Breaker at Sub #2 Fails
4. Breaker Fail Relay at Sub #2 Operates
5. All breakers on bus at Sub #2 Open

Simplified System One Line

(Note: Sub #2 has more detail)

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)	
Name:	Jonathan Sykes
Organization:	SRP
Telephone:	602-236-6442
E-mail:	jonathan.sykes@srpnet.com

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ ERCOT	☒	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs and ISOs
☐ MRO	☐	3 — Load-serving Entities
☐ NPCC	☐	4 — Transmission-dependent Utilities
☐ RFC	☐	5 — Electric Generators
☐ SERC	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ SPP	☐	7 — Large Electricity End Users
☒ WECC	☐	8 — Small Electricity End Users
☐ NA – Not Applicable	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment: Reword to: Transmission planning period that covers years six or beyond.**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☐Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that	☐Agree.

cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Do not agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.

- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☐
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☐
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☐

Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☐
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☐

Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	The time to adjust the system needs to be provided (when does a N-1-1 become a N-2?). If the cause of the outage is transient (temporary) the operator needs some time to test and restore the element (could be minutes up to several hours). If the element is lost indefinitly, the operator will need some minimum time to adjust the system. If this time is not available prior to the next N-1 then the standard should allow Non-Consequetial Loss of Load.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	same as Q21
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	same as Q21

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance

requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment:

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	The time to adjust the system needs to be provided (when does a N-1-1 become a N-2?). If the cause of the outage is transient (temporary) the operator needs some time to test and restore the element (could be minutes up to several hours). If the element is lost indefinitly, the operator will need some minimum time to adjust the system. If this time is not available prior to the next N-1 then the standard should allow Non-Consequetial Loss of Load. Some distinction needs to be made the amount of generation connected at a single point on the BES. a wind farm might have many small generators connected to the BES with an aggregate total of 300Mw or more. This requirement will should only apply to generating sources that might be connected to the BES through a single transformer (i.e. wind farm) with minimum agregate total of 300MW (for N-1).
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	same as Q26.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission	☐Agree. ☒Do not agree.	same as Q26.

[1] System adjustment can be manual or automatic

circuit		
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	same as Q26.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load

model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: The loss of transmission line (N-1) may require Gen drop to prevent instability or violation. Studies will need to be performed that study the congestion of generation and transmission cooridors and loss of various elements.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: As long as Non-Consequential Loss of Load is not a solution for single contingencies (N-1).

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Non-Consequential Loss of Load should not be allowed for single contingencies (N-1) and the system must remain stable with no violations.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: Non-Consequential Loss of Load should not be allowed for single contingencies (N-1) and the system must remain stable with no violations.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: The SDT should be commended for very good work at identifying many different issues of the TPL standards. However, TPL-001-1 should take into account the consequences of a Security-Based or Dependability-Based Misoperation (and failure) of the Protection System.

1) A Security-Based Misoperation of the Protection System may remove additional elements of the BES and could be listed in the table under "multiple contingency".

2) A Dependability-Based Misoperation (or Failure) of a non-redundant Protection System could cause long time delays in clearing faults and clear a large area of BES around the faulted Element. This type of failure may not provide local tripping or breaker failure initiation and remote Protection Systems would need to operate to isolate

the fault or disturbance. Often the operation of the remote Protection Systems would cause long time delays in isolating faults and disturbances.

a) The BES should be studied and those elements need to be identified where Dependability-Based Misoperations (or failures) would prevent meeting the performance requirements of Table 1 (Steady State) or Table 2 (Stability). This type of Misoperation (or Failure) will have to be included in the Tables.

For example, some parts of the BES may be able to survive long time delayed clearing of faults caused by Dependability-Based Protection System Misoperations (or failures) and still meet the performance requirements of the tables. But other parts of the BES may experience cascading outages for this same scenario. One solution to minimize the consequences of Dependability-Based Misoperations (or failures) is to install redundant Protection Systems. The redundant Protection Systems would reduce the possibility of a single Dependability-Based Misoperation (or failure) from affecting the isolation of faults and disturbances.

In addition, the TPL-001 standard will need definitions of Security-Based Misoperation and Dependability-Based Misoperation. The following definitions are used for PRC-004-WECC-1:

Security-Based Misoperation: The incorrect operation of a Protection System or RAS for faults or disturbances outside the intended zone of protection. Security is a component of reliability and is the measure of a device's certainty not to operate falsely.

Dependability-Based Misoperation: Any of the following:

☐ The absence of a Protection System or RAS operation when intended

☐ A Protection System or RAS equipment failure is alarmed or indicated to operating personnel.

☐ A Protection System or RAS equipment failure is discovered.

Dependability is a component of reliability and is the measure of a device's certainty to operate when required.

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**
Name:
Organization: Santee Cooper
Telephone: 843-761-8000
E-mail:

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☒ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☒	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☒	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☒	5 — Electric Generators
	☒	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: **Santee Cooper**
Lead Contact: **Terry L. Blackwell**
Contact Organization: **Santee Cooper**
Contact Segment: **01**
Contact Telephone: **843-761-8000 ext 5196**
Contact E-mail: **tlblackw@santeecooper.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
James Peterson	Santee Cooper	**SERC**	01
Shawn T. Abrams	Santee Cooper	SERC	01
Vicky Budreau	Santee Cooper	SERC	01
Art Brown	Santee Cooper	SERC	01
William Gaither	Santee Cooper	SERC	01
Glenn Stephens	Santee Cooper	SERC	01
Rene' Free	Santee Cooper	SERC	01
Frank Caston	Santee Cooper	SERC	01
Rick Thornton	Santee Cooper	SERC	01
James M. Jackson	Santee Cooper	SERC	01

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment: Delete the phrase "and reactive resources." It is redundant.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: The term "mis-operation" introduces ambiguity into the definition, and should be deleted. The definition needs further clarification for consequential and non-consequential loads. For example, loads served downstream from the faulted element but not directly connected should also be considered to be consequential loads. A better name for this would be "direct load loss".**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: A number of the non-extreme events also have a low probability. Recommend change the word to "lower."**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: It is suggested that another definition be added for "operations planning horizon".**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs	☐Agree.

through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Do not agree.
Q6. **Comment: A better name for this would be indirect load loss.**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Bulk Electric System deficiencies rather than needs should be evaluated. We do not agree that the planning assessment should include asset conditions and age. The age of equipment, if it is well maintained, has little impact on reliability. The term "and other factors" should be better defined or deleted.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Change to: "Events that are simulated or assessed to test the transmission system to ensure that performance requirements are met."**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: The definition should end at the semi-colon. The remaining part of the definition should be moved to the definition of "System Stability Study."**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: see Q9 above.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment: The last sentence in the above definition was not included in the definition listed in the draft standard, nor should it be.**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: These factors vary between areas and regions. In addition the TP should be allowed to assess an alternate sensitivity if they can document that it is more appropriate,

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The standard may offer guidance but what constitutes a "reasonably stressed" case should be left to the discretion of the entity performing the study, since they are the best judge of what stresses the system.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐

Comment: The entity performing the studies should be allowed to determine the appropriate sensitivity studies that need to be evaluated. An alternate approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency. Stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: We concur with the current approach.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: It should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is considered controllable and quantifiable resource.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒
Comment: Re-testing should be required only where the correction may impact network flows. The study area should be determined by the TP. The TP has the most knowledge of how the system responds to changes. The majority of transmission projects consist of the upgrading of terminal equipement or conductor on one or more branches. The only significant change that such upgrade work would change in a powerflow model would be that of the branch (facility) ratings would change. It is not necessary to rerun powerflow simulations for such cases, as it can be determined by inspections whether the upgrade work would be sufficient to move the facility rating above the expected normal or contingency flow.

We agree that the Planning process should ensure that corrective actions for a particular defeciency do not lead to other deficiencies. However, the process for ensuring this is not necessarly The development of new study cases which include facilities comprising the corrective action plan and the suscetesting is not needed.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒

Comment: The goal is to meet the system performance requirements outlined in the standard. Whether a project is proposed or committed is irrelevant. R2.7.3 should be deleted.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒

Comment: The goal is to meet the system performance requirements outlined in the standard. Whether a project is proposed or committed is irrelevant. R2.7.4 should be deleted.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to “raise the bar.” Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	We do not agree with the concept of non-consequential load loss. To maintain system reliability, the disconnect of any load should be allowed.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another	☐Agree. ☒Do not agree.	We do not agree with the concept of non-consequential load loss. To maintain system reliability, the disconnect of any load should be allowed.By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a

Transmission circuit		problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒

Comment: By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment

Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	The event should be tested for ensuring or maintaining reliability of the BES, however direct load loss should be allowed.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	Same comment as question #26.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	Same comment as question #26.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	Same comment as question #26.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒
Comment: AC and DC contingency events should be treated the same.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

---

[1] System adjustment can be manual or automatic

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment: The transmission planner should have discretion to consider the appropriate number of units to be tripped based on the station design, and/or relay design.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒

Comment: The characterisitics of detailed induction load are generally lacking to properly model induction loads. Load modeling should be left to the judgement of the TP.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Any adjustments should be allowed that protects the reliability of the BES.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Generator runback schemes should be able to be implemented before emergency thermal rating time limits are exceeded.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: There should be no stability impacts, and system security must be maintained. RAS or SPS should meet the same criteria as any protection system.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: There should be no stability impacts, and system security must be maintained. The requirements are outlined in PRC-015,016, and 017.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment: The proposed standard as well as the existing standards, makes no distinction between firm (network resource) and non-firm (energy only) generation. The standards should clearly state that the standard does not apply to non-firm generation.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment: Transmission Planners are currently able to maintain adequate levels of reliability using the existing TPL-001 thru TPL-004 standards. While incremental improvements can be made, it is not evident that prescribing more stringent planning requirements will result in significant reliability improvements.

Table 1 in the column titled "Interruption of Firm Transfer Allowed," does it pertain to point-to-point only, or does it also apply to network loads? Please explain how this provision is consistent with the requirement to re-dispatch to address system constraints.

There are no explicit performance requirements for normal system performance.

Requirement R1.1.2 refers to "normal weather patterns as agreed to by the Planning Coordinator(s) and the Transmission Planner(s)…" The standard and the ERAG MMWG need to be made consistent.

Requirement R2.3 There are no performance requirements for Short Circuit Studies.

Requirement R2.7.1.1 specifies a "project initiation date". This information is not needed for system reliability purposes.

Requirement R3.2. There should be some flexibility for simulation of planning events. For certain areas of the BES, the resulting configuration after operator intervention could be more severe than the removal of all elements. For example, the operation of a transmission line with one end open may be more severe than opening both ends of the line. This respresents actual operation in order to restore service to stations on the line.

Requirement R3.3.2.1 requires an evaluation for "Consequential Load loss (expected maximum demand and expected duration). Load loss is not an ERO responsibility.

Requirement R3.3.2.2 does not permit the "shedding of firm Load or curtailment of firm transfers". This is not an ERO responsibility.

Requirement R3.6 states "Manual and automatic generation tripping is allowed for multiple Contingencies and for single Contingencies only in situations that meet all of the following conditions: TBD. Generators should be allowed to trip for single and multiple contingencies as long as Facility Ratings are not exceeded. In addition, generators should be allowed to trip for any condition that imperils the generator. System performance should be the criteria, not generator operating state.

Requirement R4.2 states "Contingency analyses shall simulate the removal of all elements including those that the System protection is expected to disconnect for each Contingency without operator intervention." Delete "including those".

Requirement R4.6.1 states that Plant Stability studies "Shall be performed for individual generating units 20 MW or greater…" Does this mean that studies must be performed for all units? Many plants have "sister units" that are essentially the same. This requirement seems to be excessive.

The R1 requirements should be deleted from this standard and should remain on the MOD standards. (MOD-010, MOD-012, and MOD-018)

Requirement R4.6.2 states that Plant Stability studies "Shall be performed for changes in the real power output of a generating unit by more than 10% of the existing capability or more than 20 MW whichever is greater." The meaning of this wording is unclear.

Requirement R4.6.3 states that Plant Stability studies "Shall be performed and evaluated for those Planning Events that would produce more severe System impacts and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. The identified Contingencies, at a minimum, shall be evaluated." The use of "evaluation/evaluated is unclear. Is an evaluation the same as performing a study? If not, what does it mean to select a contingency for evaluation?

The standard needs to define or describe the difference between a "bus" and a "bus section".

Table I, P3, P7.2, P9.6 and Table 2, P7 need some punctuation for clarification.
Table I, P9.6 and Table 2, P9, why study replacing an outaged transformer with a spare?

The use of the terms "bus", "non-tie bus", and "bus section" are not clear. In P7-2 what is meant by the phrase or a bus and a stuck non-bus tie breaker ? Does this imply a bus or a bus section? How would you model this?

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

<table>
<tr><th colspan="3">Individual Commenter Information
(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td>Name:</td><td colspan="2">Wayne Guttormson</td></tr>
<tr><td>Organization:</td><td colspan="2">Submitted for Saskatchewan Power Corp. & the Sask. Regulatory Jurisdiction</td></tr>
<tr><td>Telephone:</td><td colspan="2">306-566-2166</td></tr>
<tr><td>E-mail:</td><td colspan="2">wguttormson@saskpower.com</td></tr>
<tr><td>NERC Region (check all Regions in which your company operates)</td><td></td><td>Registered Ballot Body Segment (check all industry segments in which your company is registered)</td></tr>
<tr><td rowspan="10">☐ ERCOT
☐ FRCC
☒ MRO
☐ NPCC
☐ RFC
☐ SERC
☐ SPP
☐ WECC
☐ NA – Not Applicable</td><td>☒</td><td>1 — Transmission Owners</td></tr>
<tr><td>☐</td><td>2 — RTOs and ISOs</td></tr>
<tr><td>☒</td><td>3 — Load-serving Entities</td></tr>
<tr><td>☐</td><td>4 — Transmission-dependent Utilities</td></tr>
<tr><td>☒</td><td>5 — Electric Generators</td></tr>
<tr><td>☒</td><td>6 — Electricity Brokers, Aggregators, and Marketers</td></tr>
<tr><td>☐</td><td>7 — Large Electricity End Users</td></tr>
<tr><td>☐</td><td>8 — Small Electricity End Users</td></tr>
<tr><td>☐</td><td>9 — Federal, State, Provincial Regulatory or other Government Entities</td></tr>
<tr><td>☐</td><td>10 — Regional Reliability Organizations and Regional Entities</td></tr>
</table>

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: What is meant by directly connected? Local area network load is allowed to be shed in Saskatchewan. The Saskatchewan Regulatory Jurisdiction has no plans to change this unless there is technical evidence to justify the increase in reliability.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Suggest that the definition be changed to state "lower probability of occurrence than Planning Events."**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding,	☐Agree. ☒Do not agree.

or Special Protection Systems.	
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: What is the intent "and other factors, such as asset condition and age"? Seems to broad and outside the scope of NERC. Remove it.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii “Sensitivity studies and critical system conditions” FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment:

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: Unnecessary micro-management of the planning process in the Saskatchewan Regulatory Jurisdiction.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material

changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒

Comment: The SDT should justify that the benefit to customers of this increased reliability justifies the cost.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: The SDT should justify that the benefit to customers of this increased reliability justifies the cost.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	Local area network load is allowed to be shed in Saskatchewan. The Saskatchewan Regulatory Jurisdiction has no plans to change this unless there is technical evidence to justify the increase in reliability. The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	Local area network load is allowed to be shed in Saskatchewan. The Saskatchewan Regulatory Jurisdiction has no plans to change this unless there is technical evidence to justify the increase in reliability. The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	Local area network load is allowed to be shed in Saskatchewan. The Saskatchewan Regulatory Jurisdiction has no plans to change this unless there is technical evidence to justify the increase in reliability. The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above	☐Agree. ☐Do not agree.	

[1] System adjustment can be manual or automatic

300 kV		

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: Why is this concept not applied to AC tie-lines between systems, whether single or multiple? In Saskatchewan's case there is very little difference.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: What is the purpose of requiring this event or any other extreme event to be studied? We see little benefit in this. In the Saskatchewan context we accept the risk and consequences for extreme events as there is usually very little justification for the increase in reliability versus the economic cost. Saskatchewan plans and designs its system to fail safe in those events and restores the system thereafter.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: The amount of generation change should be limited to the amount that can be accomplished within the allowed readjustment period. Due consideration should be given to start up time and ramp rates of the units. Generation rejection should not exceed the normal operating reserve.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment:
Several generation run back or generation rejection schemes are used in Saskatchewan to restore facility loading to with normal ratings. The costs of not using these schemes would involve substantial increased investments and environmental impacts unacceptable in the Saskatchewan Regulatory Jurisdiction. Conditions are

determined on a case by case basis. However, the generation runback or generation rejection scheme should not exceed the normal operating reserve.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Delegate this issue to the Planning Coordinators.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: Delegate this issue to the Planning Coordinators.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☐ No ☐
Comment: Saskatchewan commends the SDT for taking on this difficult and important task. We wish you good fortune.

Local area network load is allowed to be shed in Saskatchewan for single contingencies, and the interruption of firm transfers are allowed over our DC tie and AC tie-lines. The Saskatchewan Regulatory Jurisdiction has no plans to change this unless there is technical evidence to justify the increase in reliability versus the cost.

Also for P9-1, is there any justification for the selection of one mile? If there is none the development of exemption criterion should be delegated to the Planning Coordinator. It is not what Saskatchewan has used in designing its system, and it is going to involve a significant capital outlay for Saskatchewan with questionable reliability benefits.

Saskatchewan will not support the default value of 1 mile unless there is a technical study (including reliability benefit versus cost) to support it as opposed to any other distance.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**	
Name:	Scott Inglebritson
Organization:	Seattle City Light
Telephone:	206-684-3491
E-mail:	scott.inglebritson@seattle.gov

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☒	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☒Agree. ☐Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: List specific types of failures or direct us to a specific table which describes planning events.**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☒Do not agree.
Q9. **Comment: "...in the vicinity of the plant..." needs to be more specific. How far away must we study?**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☒Do not agree.
Q11. **Comment: Base cases are developed and studied for seasons, not calendar years. Can the the Year One reference be changed to "the year beginning at the next Winter season" instead of the specific "...next calendar year"?**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: Sensitivity studies should be performed at a level higher than LSE or BA. It seems more appropriate for a RC or RRO to determine regional contingencies.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☒ No ☐
Comment:

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: Conditions six years or more in the future are unpredictable and sensitivity studies would provide results of limited usefulness.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: Sensitivity studies should be adequate to determine the study area. Starting at the corrective facility, work out bus by bus, determining sensitivity to the facility's loss. Boundaries of the study area would be defined at buses where loss sesitivity is (for example) 1% or less.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: Since compliance with performance guidelines is mandated, aren't all projects defined in the corrective action plans "committed" projects? Proposed projects in the context of Requirement 2.7 should only exist in the studies to determine which remedial solution(s) comprise the Corrective Action Plan.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: To agree with the comment in Q18, the requirement should read "Corrective Action Plans shall not be modified without documentation to show that the revised plan meets the performance requirements."

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to “raise the bar.” Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Loss of two major HV elements can drive our region into undervoltage conditions, forcing us to shed non-consequential load per UVLS standard requirements.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Same as Q21, loss of elements of this size may initiate UVLS.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	Same as Q21.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: Adequacy of HV supply is outside of our control but may have a detrimental effect on our system. We should not be required to supplement the existing high-voltage infrastructure when it is the responsibility of the transmission owner. If the intent of this requirement is to prevent downstream load loss caused by a fault in the 300kV beloning to the transmission owner, then we agree. We must be able to shed load when our supply is cut.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: As in Q24. Certain combinations in the HV supply system will force us to shed load.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	

[1] System adjustment can be manual or automatic

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: Otherwise, we need reserve transfer capacity equal to the total of the firm transfers, which is not very cost effective!

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Any adjustment required to respond to a contingency should be allowed, unless it adversely impacts the regional system.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Runback should be allowed to prevent a possible cascading outage which might result from the thermal overload, but only to that level needed to protect the equipment, to address the contingency, or to prepare for the next contingency. If the runback level is lower than the normal rating, it should be shown that this runback will not harm the stability of the system.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐

Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: All RAS or SPS schemes should be evaluated to determine the impact on the interconnected system. Actions that derate transfer paths should not be allowed unless essential to protecting equipment or anticipating the next contingency.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: Actions should be intended to address contingency, prevent damage, or prepare for next contingency.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: The additional studies required by this proposed standards are going to put a burden on our utility. We do not have the additional human resources available to perform so much additional work. Also, the stipulation that no "non-consequential load" loss may occur will put a financial burden on our utility. We have always planned assuming that we would able to be shed residential load in case of an emergency caused by a N-2 event or regional outage beyond our control.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: **SERC EC Dynamics Review Subcommittee (DRS)**

Lead Contact: **Sharma Kolluri**

Contact Organization: **Entergy**

Contact Segment: **1**

Contact Telephone: **504-576-4045**

Contact E-mail: **vkollur@entergy.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
Rick Foster	Ameren	**SERC**	1
Anthony Williams	Duke Energy Carolinas	SERC	1
Sujit Mandal	Entergy	SERC	1
John O'Connor	Progress Energy Carolinas	SERC	1
Bob Jones	Southern Company Services, Inc. - Trans	SERC	1
Lee Taylor	Southern Company Services, Inc. - Trans	SERC	1
Tom Cain	Tennessee Valley Authority	SERC	1

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the

rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: Add the following to the end of the definition: "or unintentional load lost as a direct result of the event (e.g. load dropout due to low voltages as a result of a fault)."**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: A number of the non-extreme events also have a low probability. Recommend change the word to "lower." The definition for "Extreme Events" should reference Table 1.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs	☒Agree.

through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Delete the word "needs" and the phrase "such as asset conditions and age." We do not agree that the planning assessment should include asset conditions and age. The age of equipment, if it is well maintained, has little impact on reliability.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Delete the term "the effect on the System of." The reference to "System" causes confusion with the term "System Stability Study."**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the

requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The entity performing the studies has the best system specific knowledge to select the appropriate sensitivities that needs to be evaluated.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The entity performing the studies has the best system specific knowledge to determine what constitutes a reasonable stressed case.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐

Comment: Use of sensitivity studies is appropriate only for System Stability Studies.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: We agree that sensitivity studies should not be required for the Long-Term..

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2

will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☐
Comment:

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☐
Comment:

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☐
Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒

Comment: By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost. It would be helpful if "bus tie breaker" was defined (e.g. is the middle breaker in a breaker and a half scheme considered a bus tie breaker?).

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

[1] System adjustment can be manual or automatic

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒
Comment: DC and AC contingency events should be treated the same.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: This question conflicts with Table 2 Extreme Event 9. However, we feel it is not necessary to simulate loss of all units at a station because simultaneous loss of all units is unlikely.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☒
Comment: In general this is a good practice. Dynamic studies of seasonal load conditions should include the effects of induction motors, and particularly in areas where traditional load models have indicated a problem. Unfortunately, there is a lack of data to support the amount and characteristics of the detailed induction load models in many areas. In addition to the consideration of the dynamic effects of induction motor loads, the effects of static capacitor banks installed at distribution voltage levels would need to be considered as well. Prior to making this a requirement in the reliability standards, the industry needs guidance as to how this data should be developed and maintained for models in future years. A long term transition period is required to incorporate motor models into dynamics studies.

Note that meeting such a requirement would necessitate a significant increase in the dynamic data needed to represent the system. Maintenance of such load model data would require significant resources. Load characteristics valid for a near term model might not be valid for future years.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Manual and automatic adjustments should be allowed for single and multiple contingencies as long as performance requirements are met.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☒
Comment: The question is not clear. Generation runback schemes are acceptable as long as emergency ratings are not violated. Runback schemes should not be used to restore an element to within emergency ratings.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: no limitations

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: no additional conditions except meeting performance requirements.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: In the Stability Performance Table, under contingency P8 with a line out add a generator contingency. and with a transformer out add a generator and a line contingency.

In the Stability table change the Extreme events numbering to E1, E2, etc.

In R4.6 and other locations, the generator exemption of 20 MW should be increased to 75 MVA.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: **SERC EC Planning Standards Subcommittee**

Lead Contact: **Travis Sykes**

Contact Organization: **Tennessee Valley Authority**

Contact Segment: **1**

Contact Telephone: **423-751-4162**

Contact E-mail: **tssykes@tva.gov**

Additional Member Name	Additional Member Organization	Region*	Segment*
Darrell Pace	Alabama Electric Coooperative	**SERC**	1
John Sullivan	Ameren	SERC	1
Charles Long	Entergy	SERC	1
David Weekley	MEAG Power	SERC	1
Allen McKee	Midwest ISO (MISO)	SERC, MRO, RFC	2
Pat Huntley	SERC Reliability Corp	SERC	10
Phil Kleckley	SC Electric and Gas	SERC	3
Bob Jones	Southern Company Services	SERC	1

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the

rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: The term "mis-operation" introduces ambiguity into the definition, and should be deleted. The definition needs further clarification for consequential and non-consequential loads. For example, loads served downstream from the faulted element but not directly connected should also be considered to be consequential loads.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: A number of the non-extreme events also have a low probability. Recommend change the word to "lower." The definition for "Extreme Events" should reference Table 1.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	

Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Bulk Electric System deficiencies rather than needs should be evaluated. We do not agree that the planning assessment should include asset conditions and age. The age of equipment, if it is well maintained, has little impact on reliability.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Change to: "Events that are simulated or assessed to test the transmission system to ensure that performance requirements are met."**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment: Change "System" to "Bulk Electric System." Need a definition for "plant."**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment: Change "System" to "Bulk Electric System."**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment: The last sentence in the above definition was not included in the definition listed in the draft standard, nor should it be.**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The entity performing the studies should be allowed to determine the appropriate number of cases that need to be evaluated.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The standard may offer guidance but what constitutes a "reasonably stressed" case should be left to the discretion of the entity performing the study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐

Comment: The entity performing the studies should be allowed to determine the appropriate sensitivity studies that need to be evaluated. An alternate approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency. Stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: We concur with the current approach.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: It should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is considered firm.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: Re-testing should be required only where the correction may impact network flows. The study area should be determined by the TP. The TP has the most knowledge of how the system responds to changes.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: The goal is to meet the system performance requirements outlined in the standard. Whether a project is proposed or committed is irrelevant.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: see answer to Q18.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	see Q20 above.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	see Q20 above.
Q23. P5-3: For facilities	☐Agree.	see Q20 above.

above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☒Do not agree.	

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: see Q20 above.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: see Q20 above.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☐Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	

[1] System adjustment can be manual or automatic

Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Generator protection is designed to trip only those units required. In addition, it is the magnitude of generation tripped rather than the number of units tripped that is of the greatest significance to the stability of the grid.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒

Comment: Dynamic studies of seasonal load conditions should include the effects of induction motors, and particularly in areas where traditional load models have indicated a problem. Unfortunately, there is a lack of data to support the amount and characteristics of the detailed induction load models in many areas. In addition to the consideration of the dynamic effects of induction motor loads, the effects of static capacitor banks installed at distribution voltage levels would need to be considered as well. Prior to making this a requirement in the reliability standards, the industry needs guidance as to how this data should be developed and maintained for models in future years.

Note that meeting such a requirement would necessitate a significant increase in the dynamic data needed to represent the system. Maintenance of such load model data would require significant resources. Load characteristics valid for a near term model might not be valid for future years. Also, summer peak load, winter peak load, and off-peak load characteristics would differ.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Adjustments that should be allowed are those that can be performed in time to prevent the system from failing to meet performance requirements. These adjustments may include automatic voltage regulator action, governor action, generator runback, and generator tripping.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that

must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: The generator runback scheme should complete its action within the time allowed by the emergency ratings of elements that exceed their normal thermal ratings.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: RAS or SPS should meet the same criteria as any protection system.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: The conditions required by SPS standards (PRC).

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☐
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: Significant Increase in Study Activity Workload on Transmission Planners: The increase in both steady state and dynamic studies required to ensure compliance with the proposed standards will result in increased costs and staff additions. The addition of the "Corrective Action Plan" requires the TP to provide a significant amount of documentation for each deficiency identified by the studies. Also, R3.2 requires that the studies simulate the protection scheme for all events. The current software tools cannot automate these studies for bus faults and breaker failure events, requiring each scenario to be studied manually. Additionally, experienced staff capable of performing analyses

as described in the proposed standard have become increasingly difficult to find and retain and the talent pool of people with these skills has recently become depleted to alarming levels.

Implementation Plan:
Given the intent of the proposed standard to encourage large scale investment in the EHV system, full implementation will take years, perhaps decades. Acquirement of right-of-way for new EHV lines has become increasingly difficult in recent years and inreasingly expensive. Legal, regulatory, and other difficult issues often take several years to navigate, even for 115kV lines. The Implementation Plan timeframe, if set too short, would be unduly burdensome on Transmission Owners forcing them to be less dicretionary with funds than would be prudent. The proposed implementation plan should include provisions for those cases where viable solutions simply can not be implemented in time due to circumstances beyond the control of Transmission owners. We recommend a minimum of 15 years for the transition.

Design and Construction Constraints:
Even if right-of-way and other legal and regulatory hurdles are cleared, and the capital funding for such a tremendous level of investment was not an issue, the other resources required to actually construct the projects are equally difficult and costly to secure. Raw material prices on comodities like copper and steel have skyrocketed in recent years. Additionally, the skilled labor and Engineering resources are constrained with labor rates almost keeping up with other resource costs. Overall project costs have more than doubled over the last 7-10 years. Recent press releases concerning new generation being planned and then scrapped due to the rapid escalation of project costs are public evidence of this. The inflationary mark-up is impossible to estimate but much less will be built with the same capital investment than is currently envisioned.

Cost-Benefit Analysis:
The proposed standard will be exceedingly expensive to become compliant with unprecedented levels of capital investment in Transmission facilities. Before the standard comes to official vote, it would be prudent for a cost-benefit analysis to be performed to determine if the reliability improvements truly justify the huge expenditures certain under the proposed standard. Additionally, as many jurisdictional rate structures share the cost of such investments between retail and wholesale customers, cost-benefit analyses should be completed for both retail and wholesale customers.

System Adjustment Clarification:
The term "System Adjustment" as outlined in the tables should be better defined. The use of generation for redispatch may have nuances which preclude or otherwise limit their use for studies. Perhaps some clearer guidelines on what is allowed would facilitate transparency and coordination between Transmission Planners.

Transmission Service Evaluation:
A major concern is that the proposed standard appears to be disjointed from the requirements for selling firm Transmission Service. The increase in reliability gained from the proposed standard would, in some regions, quickly be eroded by new firm sales if those sales are based on the historical N-1 ATC requirements. The proposed standard must be applied to long-term firm transmission service requests if Transmission reliability is to be truly enhanced. If the standard is not applied to Transmission Service evaluation, reliability levels for the different classes of firm customers will diverge.

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

<table>
<tr><th colspan="3">Individual Commenter Information
(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td colspan="3">Name:</td></tr>
<tr><td colspan="3">Organization:</td></tr>
<tr><td colspan="3">Telephone:</td></tr>
<tr><td colspan="3">E-mail:</td></tr>
<tr><td>NERC Region (check all Regions in which your company operates)</td><td></td><td>Registered Ballot Body Segment (check all industry segments in which your company is registered)</td></tr>
<tr><td rowspan="10">☐ ERCOT
☐ FRCC
☐ MRO
☐ NPCC
☐ RFC
☐ SERC
☐ SPP
☐ WECC
☐ NA – Not Applicable</td><td>☐</td><td>1 — Transmission Owners</td></tr>
<tr><td>☐</td><td>2 — RTOs and ISOs</td></tr>
<tr><td>☐</td><td>3 — Load-serving Entities</td></tr>
<tr><td>☐</td><td>4 — Transmission-dependent Utilities</td></tr>
<tr><td>☐</td><td>5 — Electric Generators</td></tr>
<tr><td>☐</td><td>6 — Electricity Brokers, Aggregators, and Marketers</td></tr>
<tr><td>☐</td><td>7 — Large Electricity End Users</td></tr>
<tr><td>☐</td><td>8 — Small Electricity End Users</td></tr>
<tr><td>☐</td><td>9 — Federal, State, Provincial Regulatory or other Government Entities</td></tr>
<tr><td>☐</td><td>10 — Regional Reliability Organizations and Regional Entities</td></tr>
</table>

Group Comments (Complete this page if comments are from a group.)

Group Name: **SERC EC Reliability Review Subcommittee (RRS) and SERC OC Operations Planning Subcommittee (OPS)**

Lead Contact: **James E. (Jim) Peterson, RRS Chair**

Contact Organization: **South Carolina Public Service Authority**

Contact Segment: **1**

Contact Telephone: **(843) 761-8000 x5201**

Contact E-mail: **jepeters@santeecooper.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
Curtis Stepanek	Ameren	**SERC**	1
Brian D. Moss	Duke Energy Carolinas	SERC	1
Kham Vongkhamchanh	Entergy	SERC	1
Ken Wofford	Georgia Transmission Corp.	SERC	1
Denise Roeder	NC Municipal Power Agency #1	SERC	3
Al McMeekin	SC Electric & Gas Company	SERC	1
Clay Young	SC Electric & Gas Company	SERC	3
Rod Hardiman	Southern Company Services, Inc. - Trans	SERC	1
Ian Grant	Tennessee Valley Authority	SERC	1
Marjorie Parsons	Tennessee Valley Authority	SERC	1
Carter Edge	SERC Reliability Corporation	SERC	10
Maria Haney	SERC Reliability Corporation	SERC	10
Eugene Warnecke	Ameren	SERC	1
Chris Bradley	Big Rivers Electric Corporation	SERC	1
Jerry Tang	Municipal Electric Authority of Georgia	SERC	1
Phil Creech	Progress Energy Carolinas	SERC	1
Doug McLaughlin	Southern Company Services, Inc. - Trans	SERC	1
Michael Clements	Tennessee Valley Authority	SERC	1

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the

rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment: Delete the phrase "and reactive resources."**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: The term "mis-operation" introduces ambiguity into the definition, and should be deleted. The definition needs further clarification for consequential and non-consequential loads. For example, loads served downstream from the faulted element but not directly connected should also be considered to be consequential loads. A better name for this would be "Planned Load Loss."**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: A number of the non-extreme events also have a low probability. Recommend change the word to "lower."**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: It is suggested that another definition be added for**	

"operations planning horizon".	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: A better name for this would be "Unplanned Load Loss". Load loss that occurs from UFLS, UVLS, load shedding or SPS should be moved to Planned Load Loss. Unplanned load loss would be all other load loss other than planned.**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Bulk Electric System deficiencies rather than needs should be evaluated. We do not agree that the planning assessment should include asset conditions and age. The age of equipment, if it is well maintained, has little impact on reliability. The term "and other factors" should be better defined or deleted.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Change to: "Events that are simulated or assessed to test the transmission system to ensure that performance requirements are met."**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: The definition should end at the semi-colon. The remaining part of the definition should be moved to the definition of "System Stability Study."**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: see Q9 above.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment: The last sentence in the above definition was not included in the definition listed in the draft standard, nor should it be.**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: These factors vary between areas and regions. In addition the TP should be allowed to assess an alternate sensitivity if they can document that it is more appropriate,

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The standard may offer guidance but what constitutes a "reasonably stressed" case should be left to the discretion of the entity performing the study, since they are the best judge of what stresses the system.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐

Comment: The entity performing the studies should be allowed to determine the appropriate sensitivity studies that need to be evaluated. An alternate approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency. Stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: We concur with the current approach.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: It should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is considered firm.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒
Comment: Re-testing should be required only where the correction may impact network flows. The study area should be determined by the TP. The TP has the most knowledge of how the system responds to changes.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: The goal is to meet the system performance requirements outlined in the standard. Whether a project is proposed or committed is irrelevant. R2.7.3 should be deleted.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒

Comment: The goal is to meet the system performance requirements outlined in the standard. Whether a project is proposed or committed is irrelevant. R2.7.4 should be deleted.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Q22. P5-2: For facilities above 300 kV, loss of a	☐Agree.	By not allowing non-consequential load loss, utilities will incur significant

Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Do not agree.	expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒

Comment: By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	It is agreed that this event should be tested for maintaining reliability of the BES, however planned load loss should be allowed.
Q27. P4-2: Loss of a	☐Agree.	same comment as for Q26.

[1] System adjustment can be manual or automatic

generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Do not agree.	
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	same comment as for Q26.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	same comment as for Q26.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒
Comment: DC and AC contingency events should be treated the same. The question is somewhat obscure.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment: It is not necessary to simulate loss of all units at a station. The Transmission Planner or Planning Authority should have the discretion to consider the appropriate number of units to be tripped based on station design, relay design, etc.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒

Comment: There is a lack of data to support the amount and characteristics of the detailed induction load models in many areas. Transmission planners should be able to use the latest information and techniques.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Any adjustments should be allowed that protects the reliability of the BES.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that

must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment:

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: RAS or SPS should meet the same criteria as any protection system.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: The requirements are outlined in PRC-015, 016, and 017.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment: Not currently aware of any.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment:
Cost-Benefit Analysis:

Transmission Providers are currently able to maintain adequate levels of reliability using existing standards. While incremental improvements can be made, it is not evident that prescribing more stringent planning requirements will necessarily result in signifcant reliability improvements.

The proposed standard will be exceedingly expensive to become compliant with unprecedented levels of capital investment in Transmission facilities. Before the standard comes to official vote, it would be prudent for a cost-benefit analysis to be performed to determine if the reliability improvements truly justify the huge expenditures under the proposed standard.

In Table 1 in the column titled "Interruption of Firm Transfer Allowed," does it pertain to point-to-point only, or does it also apply to network loads? Please explain how this provision is consistient with the requirement to re-dispatch to address system constraints.

The terms "Consequential Load Loss" and "Non-consequential Load Loss" should be deleted and Table 1 should be modified to discuss "Planned Load Loss" and "Unplanned Load Loss". It should not matter if the load is directly connected to the failed facility or downstream and served by the failed facility. If the plan to protect the interconnected grid is to disconnect those loads using a manual process or an automatic scheme, then it should be allowed.

The R1 requirements should be deleted from this standard and should remain in the MOD standards.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Philip R. Kleckley	
Organization:	South Carolina Electric & Gas	
Telephone:	803-217-2045	
E-mail:	pkleckley@scana.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: **Transmission Planning**

Lead Contact: **Philip Kleckley**

Contact Organization: **South Carolina Electric & Gas**

Contact Segment: **3**

Contact Telephone: **803-217-2045**

Contact E-mail: **pkleckley@scana.com**

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: "Consequential Load Loss" should be termed "Intentional or Planned Load Loss". Not only should direct connected load loss be included, but loads served by or downstream from the faulted element, that is not directly connected to the faulted element, should also be included.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☐Do not agree.
Q3. **Comment:**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.

Q6. **Comment: This term is not needed. See comments on "Consequential Load Loss/Intentional Load Loss".**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Bulk Electric System deficiencies rather than needs should be evaluated.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Prefer alternate language, "Events for which Transmission system performance requirements must be met."**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: The standard may offer guidance but the entity performing the sensitivity studies should be able to determine the number of cases required.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: The standard may offer guidance but what constitutes a "reasonably stressed" case should be left to the discretion of the entity performing the study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒
Comment: Stability studies examine generator and system responses to specific conditions. Because the exact system conditions can not be determined in advance, the sensitivity analysis may not be very useful. In addition, stability studies are more time consuming than conventional power flow studies. A preferred approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This

Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: It should be included if it is a tool made available to the TP for this purpose, but only to the extent it is considered firm.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: Re-testing should be required only where the correction may impact network flows. The study area should be determined by the TP.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: The goal is to meet the system performace requirements outlined in the standard. Whethter a project is proposed or committed is irrelevant.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: See answer to question #18.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	SCE&G does not agree with the concept of non-consequential load loss. To maintain system reliability, the disconnect of any load should be allowed. If not allowed, unprecedented new transmission costs will be required. These costs will be for local area improvements and will NOT result in increased transfer capabilities for markets.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	See answer to #20.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	See answer to #20.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment	☐Agree. ☒Do not agree.	See answer to #20.

followed by loss of another transformer		

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: See answer to #20.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: See answer to #20.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	Planned load loss should be allowed.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	Planned load loss should be allowed.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	Planned load loss should be allowed.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above	☐Agree. ☒Do not agree.	Planned load loss should be allowed.

[1] System adjustment can be manual or automatic

300 kV		

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒
Comment: General there should be no difference between AC and DC; however, the answer to this question depends on the contractual arrangements associated with the transfer.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Generator protection is designed to trip only those units required. In addition, it is the magnitude of generation tripped rather than the number of units tripped that is of the greatest significance to the stability of the grid.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒

Comment: There should be an attempt to represent the dynamic behavior of induction motor loads in the generic system load representations. However, the state of induction motor load modeling is not adequate to permit discrete induction motor load models.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Adjustments that should be allowed are those that can be performed in time to prevent the system from failing to meet performance requirements. These adjustments may include automatic voltage regulator action, governor action, and generator runback.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: The generator runback scheme should complete its action within the time allowed by the emergency ratings of elements that exceed their normal thermal ratings.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: A RAS or SPS should be allowed for single contingencies if its failure or misoperation can be compensated for during the time allowed by the emergency ratings of the elements that exceed their normal thermal ratings.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: RAS or SPS should meet the same criteria as any protection system.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: The conditions required by SPS Reliability Standards.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: General Comment. Cost/Benefit analyses should be conducted on each change in a standard or new standard.

Requirement 7.2 will require a 2 bus outage test on the SCE&G transmission system. Most of our busses are straight busses and a stuck line-terminal breaker will result in a clearing of the connected bus (and all facilities connected to that bus). Our read of this requirement is that we must design the system to accommodate a stuck breaker event (outaging all connected facilities) while a different bus (and all of its connected facilities) is already outaged. This is a significant leap in the required performance of our system and will result in tremendous unwarranted costs and years of new local area transmission construction.

Requirement R1.1.2 refers to "normal weather patterns as agreed to by the Planning Coordinator(s) and the Transmission Planner(s)…" The ERAG MMWG considers normal weather to be such that the weather affected load to be that which has a 50%

probability of, plus or minus. The standard and the ERAG MMWG need to be made consistent.

Requirement R2.7.1.1 specifies a "project initiation date". This information is not needed for system reliability purposes.

Requirement R3.3.2.1 requires an evaluation for "Consequential Load loss (expected maximum demand and expected duration). Load loss is not an ERO responsibility.

Requirement R3.3.2.2 does not permit the "shedding of firm Load or curtailment of firm transfers". This is not an ERO responsibility.

Requirement R3.6 states "Manual and automatic generation tripping is allowed for multiple Contingencies and for single Contingencies only in situations that meet all of the following conditions: TBD. Generators should be allowed to trip for single and multiple contingencies as long as Facility Ratings are not exceeded. In addition, generators should be allowed to trip for any condition that imperils the generator. System performance should be the criteria, not generator operating state.

Requirement R4.2 states "Contingency analyses shall simulate the removal of all elements including those that the System protection is expected to disconnect for each Contingency without operator intervention." Delete "including those".

Requirement 4.6.1 states that Plant Stability studies "Shall be performed for individual generating units 20 MW or greater…" Does this mean that studies must be performed for all units? Many plants have "sister units" that are essentially the same. This requirement seems to be excessive.

Requirement 4.6.2 states that Plant Stability studies "Shall be performed for changes in the real power output of a generating unit by more than 10% of the existing capability or more than 20 MW whichever is greater." The meaning of this wording is unclear.

Requirement 4.6.3 states that Plant Stability studies "Shall be performed and evaluated for those Planning Events that would produce more severe System impacts and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. The identified Contingencies, at a minimum, shall be evaluated." The use of "evaluation/evaluated is unclear. Is an evaluation the same as performing a study? If not, what does it mean to select a contingency for evaluation?

The standard needs to define or describe the difference between a "bus" and a "bus section" and ensure that the use of these terms in the standard are as intended.

Table I, P3, P7.2, P9.6 and Table 2, P7 need some punctuation for clarification.
Table I, P9.6 and Table 2, P9, why study replacing an outaged transformer with a spare?

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☒ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☒	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☒	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:	**Jim Busbin**
Contact Organization:	**Southern Company Services, Inc.**
Contact Segment:	**1**
Contact Telephone:	**205-257-6357**
Contact E-mail:	**jybusbin@southernco.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
Marc Butts	Southern Company - Transmission	**SERC**	1
J. T. Wood	Southern Company - Transmission	SERC	1
Jim Viikinsalo	Southern Company - Transmission	SERC	1
Keith Calhoun	Southern Company - Transmission	SERC	1
Shih-Min Hsu	Southern Company - Transmission	SERC	1
Tom Sims	Southern Company - Transmission	SERC	1
Gary Gorham	Southern Company - Transmission	SERC	1
Dave Slovensky	Southern Company - Transmission	SERC	1
Jeremy Bennett	Southern Company - Transmission	SERC	1
Bob Jones	Southern Company - Transmission	SERC	1
Bill Botters	Southern Company - Transmission	SERC	1
Mike Bartlett	Southern Company - Transmission	SERC	1
Maryanne Mujica	Southern Company - Transmission	SERC	1
Lee Taylor	Southern Company -	SERC	1

	Transmission		
Perry Stowe	Southern Company - Transmission	SERC	1
Rod Hardiman	Southern Company - Transmission	SERC	1
Doug McLaughlin	Southern Company - Transmission	SERC	1
Randy Castello	Southern Company - Transmission	SERC	1
John Ciza	Southern Company - Generation	SERC	1
Chuck Chakravarthi Tom Higgins Terry Crawley Roger Green Roman Carter	Southern Company - Transmission Southern Company - Generation Southern Company - Generation Southern Company - Generation Southern Company - Transmission	SERC SERC SERC SERC SERC	1 5 5 5 1

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing

TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the	☐Agree. ☒Do not agree.

connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	
Q1. **Comment: As stated the definition does not appear to allow for equivalenced system representation since it refers to "each bus on the interconnected Transmission System". The words "as represented in the model" should be added after "interconnected Transmission System" or another sentence should be added stating that equivalenced system representation is acceptable. A definition of a dynamics base case should also be considered.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: This definition only relates to load that is "directly connected" to the specific element being removed. It does not allow for any load that may be or becomes radially connected through another branch that is not part of the facility removed. It does not make sense to not allow the loss of load that is actually electrically radial to the facility being outaged. The definition may work better as "Load that is no longer served because it is directly connected to or radially served through an element(s) that is removed from service due to fault clearing action." The word "mis-operation" is not needed in this definition because none of the contingency events use this term.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Recommend modifying the definition to read: "Events which are more severe than Planning events that are evaluated as required by TPL-001-1 Tables 1 and 2, in part, to identify potential Cascading Outages.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment: No Additional Comments.**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: No Additional Comments.**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment: Agree assuming the change in Q2 is made.**	
Q7. **Planning Assessment:** Documented evaluation of future	☐Agree.

Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Do not agree.
Q7. **Comment: The term "needs" should be replaced by a term that more aptly describes what is being evaluated. The definition should be ended after the word "assumptions." We do not agree that the planning assessment should include asset conditions and age. The age of equipment, if it is well maintained, has little impact on reliability.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Change to, "Events that are simulated or assessed to test the transmission system to ensure that performance requirements are met as defined in TPL-001-1 Tables 1 and 2."**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment: No Additional Comments.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment: No Additional Comments.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: The last sentence in the above definition was not included in the definition listed in the draft standard, nor should it be.**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: This should not be a "one shoe fits all" exercise. It appears that at least one of these items listed is required even though they may not be the most appropriate ones for all entities. There should be the ability to perform other sensitivity analysis instead of these as long as the "rationale" is provided for the choice. The entity should be allowed to determine the appropriate sensitivity cases.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment:

See comment above. [This should not be a "one shoe fits all" exercise. It appears that at least one of these items listed is required even though they may not be the most appropriate ones for all entities. There should be the ability to perform other sensitivity analysis instead of these as long as the "rationale" is provided for the choice. The entity should be allowed to determine the appropriate sensitivity cases.]

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐

Comment: Some sensitivity analysis is reasonable.

Other comments:

1. The wording regarding transfer sensitivity for stability analysis should be the same as the wording used in steady state analysis "modification of expected transfers".

2. The list of sensitivities may not be the most appropriate for all entities. There should be the ability to perform other sensitivity analsysis instead of these as long as the "rationale" is provided for the choice.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment:

Yes, we concur with this approach.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒

Comment: It should not be a requirement that DSM be considered but DSM should be one of the allowable alternatives. The way the present standard is written, it is unclear whether "all" of the named items (except operating procedures with the "or" statement) are required to be considered or whether only one or more of the items need to be included. It is suggested that the following statement replace the word "including" in line two of R2.7.1: "that may include one or more of the following:". This should clarify that all of the items are not required to be in the action plan for compliance.

It also is not clear what the phrase "including the duration of interim Operating Procedure" means. Does this mean how many years you would anticipate using the Operating Procedure or does it mean how long it takes to "repair" the cause of the outage that necessitated the use of the Operating Procedure? Assuming that the meaning is the second one, the requirement to document the "mean time to repair" is new and there does not seem to be a very useful purpose for this requirement. As long as the system performance standards are met and the system is prepared for the next outage, what is the purpose of recording and documenting the length of time that you anticpate it to take to fix the problem? This is variable at best and does not provide useful information.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☒
Comment:
A properly conducted study should determine that the recommended Corrective Action Plan actually solves the problem and does not cause other problems. If not, it is not a Corrective Action Plan. What appears to be intended here is whether the combination of Corrective Action Plans interact with each other and create additional problems. In the conference call Mr. Odom stated that it was not the intent for "all" the corrective plans be put back into the cases and all of the simulations be redone but only look at local area analysis. If that is the case, what is necessary to be in compliance with R2.7.2 and what type of documentation is required? This is very unclear.

The study area should be determined by the TP. The TP has the most knowledge of how the system responds to changes.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment:
This requirement does not appear to have any major benefit, particularly coupled with R2.7.4 discussed in Q19. The standards require that an assessment be done every year and that the system must meet performance requirements or a Corrective Action Plan be developed. Therefore, if a project has been previously specified as a "committed" project, removing it and or replacing it with something else must also meet performance requirements under this standard or a violation occurs. Also, this performance of the system with the "committed" Corrective Action Plan" removed or modified must be documented. Therefore, requirement R2.7.4 is automatically met and is superfluous in the standard and should be removed. There is no benefit from the distinction between a project definition of "committed" and "proposed".

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment:
See comments for Q18. [This requirement does not appear to have any major benefit, particularly coupled with R2.7.4 discussed in Q19. The standards require that an assessment be done every year and that the system must meet performance requirements or a Corrective Action Plan be developed. Therefore, if a project has been previously specified as a "committed" project, removing it and or replacing it with something else must also meet performance requirements under this standard or a violation occurs. Also, this performance of the system with the "committed" Corrective Action Plan" removed or modified must be documented. Therefore, requirement R2.7.4 is automatically met and is superfluous in the standard and should be removed. There is no benefit from the distinction between a project definition of "committed" and "proposed".]

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar."

Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures. The marginal increase in reliability for this low probability event does not justify the huge costs involved.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	This is a very significant change in the performance requirements in this reliability standard. It involves facilities from 345 kV through 764kV which carry significant amounts of power. These also are facilities that require significant lead time to construct in the Southern Balancing Authority with estimates up to 7-10 years in the state of Georgia. If a performance problem is detected under these new requirements, it could take that long to come into compliance and at a very significant cost if a new major 500kV line is required. These facilities can run as much as $4.0 million a mile or more in urban areas. We understand that a few areas of the country presently have this requirement but most do not. In the areas where the requirement has not been in place, the reliability of the system has been acceptable to the local Public Service Commissions that have governed

		the service to Retail customers. There has been no evidence presented that there is a need for an increase in reliability, particulary at the extensive time delay and expense possible from this particular requirement. An adoption of this standard without such evidence can only be considered arbitrary and capricious at best. Increased reliability is, in general, a worthy goal where it is cost effective. It may be appropriate to adopt this type of reliability requirement for areas that deem the resulting reliability increase to be cost effective for their customers. But it is inappropriate to "require" everyone else to be forced to live under this arbitrarily developed expansion of reliability requirements.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	See comments for Q21. [This is a very significant change in the performance requirements in this reliability standard. It involves facilities from 345 kV through 764kV which carry significant amounts of power. These also are facilities that require significant lead time to construct in the Southern Balancing Authority with estimates up to 7-10 years in the state of Georgia. If a performance problem is detected under these new requirements, it could take that long to come into compliance and at a very significant cost if a new major 500kV line is required. These facilities can run as much as $4.0 million a mile or more in urban areas. We understand that a few areas of the country presently have this requirement but most do not. In the areas where the requirement has not been in place, the reliability of the system has been acceptable to the local Public Service Commissions that have governed the service to Retail customers. There has been no evidence presented that there is a need for an increase in reliability, particulary at the extensive time delay and expense possible from this particular requirement. An adoption of this standard without such evidence can only be considered arbitrary and capricious at best. Increased reliability is, in general, a worthy goal where it is cost effective. It

		may be appropriate to adopt this type of reliability requirement for areas that deem the resulting reliability increase to be cost effective for their customers. But it is inappropriate to "require" everyone else to be forced to live under this arbitrarily developed expansion of reliability requirements.]
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	See comments for Q21. [This is a very significant change in the performance requirements in this reliability standard. It involves facilities from 345 kV through 764kV which carry significant amounts of power. These also are facilities that require significant lead time to construct in the Southern Balancing Authority with estimates up to 7-10 years in the state of Georgia. If a performance problem is detected under these new requirements, it could take that long to come into compliance and at a very significant cost if a new major 500kV line is required. These facilities can run as much as $4.0 million a mile or more in urban areas. We understand that a few areas of the country presently have this requirement but most do not. In the areas where the requirement has not been in place, the reliability of the system has been acceptable to the local Public Service Commissions that have governed the service to Retail customers. There has been no evidence presented that there is a need for an increase in reliability, particulary at the extensive time delay and expense possible from this particular requirement. An adoption of this standard without such evidence can only be considered arbitrary and capricious at best. Increased reliability is, in general, a worthy goal where it is cost effective. It may be appropriate to adopt this type of reliability requirement for areas that deem the resulting reliability increase to be cost effective for their customers. But it is inappropriate to "require" everyone else to be forced to live under this arbitrarily developed expansion of reliability requirements.]

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒

Comment: By not allowing non-consequential load loss, utilities will incur significant expenditures. The marginal increase in reliability for this low probability event does not justify the huge costs involved.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: By not allowing non-consequential load loss, utilities will incur significant expenditures. The marginal increase in reliability for this low probability event does not justify the huge costs involved.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	These are relatively higher probability events and the increase in performance requirements is justified.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	See comment for Q26 [These are relatively higher probability events and the increase in performance requirements is justified.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	See comment for Q26 [These are relatively higher probability events and the increase in performance requirements is justified.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☒Agree. ☐Do not agree.	See comment for Q26 [These are relatively higher probability events and the increase in performance requirements is justified.

[1] System adjustment can be manual or automatic

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☐ No ☒

Comment: Why should the reliability level for a transaction on a DC line be different from a transaction over AC? Also, when the transfer over DC is removed, the load it was serving still has to be picked up in the AC network because load cannot be dropped. Therefore, this places a burden on the AC network to serve additional load. If you allow transfers over DC to be interrupted, you should also allow the interruption of transfers over AC for the same events.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐

Comment:

No Additional Comments.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐

Comment:

No Additional Comments.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment:

No Additional Comments.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load

model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment: No Additional Comments.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Automatic generator tripping should be allowed for single contingency events and for multiple contingency events.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment: No Additional Comments.

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Yes, as long as no emergency ratings are violated.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: RAS and SPS should be defined such that they may only be used for low probability events.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Generator tripping or runback and reconfiguration should be allowed for lower probability single contingency events such as bus faults; we suggest that SPS not be used for events that are more likely to occur.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: If an SPS is used to solve a single contingency problem, then full redundancy should be required. Generator tripping or runback and reconfiguration should be allowed for lower probability single contingency events such as bus faults; we suggest that SPS not be used for events that are more likely to occur.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment: Not at this time.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment: No Additional Comments.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: See Below:

REQUIREMENTS:

1. The standard is not clear on whether corrective action plans are required for performance failures during the sensitivity analysis required for both steady-state and stability studies. In the phone conference John Odom stated that it was not the intent of the Drafting team to require that facililities be constructed for these conditions. The standard should be made clear on this point.

2. The Load Forecast section (R1.1) is new and is a duplicate of the requirements in the MOD standards and is unclear as written. Having similar requirements in multiple

standards creates the possiblility of conflicting requirements for the industry. If there are different requirements necessary, the MOD standards should be modified and not introduce a new section to the TPL standards.

3. R1.1.1 is unclear in what is intended by the "actual or expected aggregate mix of industrial, commercial, and residential load". Does the word "aggregrate" mean that the split between customer classes should be at the Balancing Authority level or at each load bus represented in the model. In many cases this could place a requirement for substantial load research on the the industry which may take a substantial amount of time and expense to accomplish. The use of the phrase "actual or expected" indicates an expectation that it be based on research and not general industry averages as may be more practical in some cases.

4. The wording in section R1.2 is very unclear. Is the intent to allow for three different methods for obtaining power factor models, i.e. historical system performance, validated by measurements during stressed System conditions, or documented Transmission planning area requirements? The other understanding is that the historical System performance is only measured during stressed System conditions. If this is the intent, what is the definition of stressed system conditions that is intended? Is this just heavy loadings, such as peak times, or is it during sytem disturbances? This is not clear. We suggest that the following words be used instead: "Load models validated by measurement during load levels typically studied or documented Transmission planning area requirements."

5. Requirement R1.4 should be qualified as only the outages within the Planning Horizon. There is no need to include protective relays because outages of relays in the Planning Horizon would not be known. We suggest the following words: "Known planned outages within the Planning Horizon and long-term outages greater than one year within the Planning Horizon for Transmission and generation equipment with consideration given to spare equipment strategy."

6. R1.5: If this places a requirement on the PC to define what constitutes "planned facilities", then this should be explicitly stated as a requirement.

7. R2.1 allows Assessments to be supplemented with "qualified" past studies which are defined in R2.6. R2.6.1 specifies these to be less than three years old for steady-state analysis and certain changes could not have occurred in the "System". There should be some qualification to the definition of "System" to include "the vicinity" of the area under evaluation. We would surmise that there always be some change in topology in the Eastern Interconnect which would preclude the use of past studies. Note that the "in the vicinity of" wording is used with the plant stability studies already. Also, is the intent with the "less than" to eliminate the use of studies three years old? Similar comments can be made for R2.6.2 and R 2.6.3.

8. R2.1 The wording/structure is confusing. The "Planning Assessment shall address all five years", but this does not require all five years be studied. It appears that the minimum study requirements would be two peak studies (years 1 or 2 & 5), one off peak study (any year), and one senstitivity case for each. Is this a correct reading?

9. In R.2.1.3.1 it is unclear what is intended. The study can be for higher or lower load "forecasts" with a different load power factor due to season, weather, or time of day. If you are looking at different seasons, weather, or time of day you will have a different load forecast. Is the intent to require the studies to model different seasons or times of

day that will generate different power factors or is it to focus on higher or lower loads, i.e. is it a load forecast exercise or a power factor exercise? Can we look at Spring conditions and have it qualify for this requirement even though the loads are consistent with my Base Case load forecast?

10. Requirement R2.1.3.3 lists "unavailability of long lead time facilities" as one of the sensitivity(ies) that should be evaluated. It is unclear whether this refers to the construction of projects with long lead times or for replacement of failed equipment that have long lead times for obtaining replacements. One of the drafting team members suggested it was the latter understanding that was intended. We suggest that the language be changed to "Delayed restoration to service of failed facilities with long lead times for repair". This may clarify the intent of the requirement.

11. R2.1.3.7 should be modified to read "Modification of planned long term Transmission outages."

12. R2.3.1 Does "current study" refer to an updated study or is this referring to some type of short-circuit analysis? It appears that analysis is required only every five years unless changes in the BES occur. Is this a correct reading?

13. R2.4: Need to clarify that "address all five years of the assessment period" does not necessarily require that each year must be studied individually. A study of one year could cover all 5 years if it is the worst case.

14. R2.4.3.2 Is the purpose of including non-firm transfers to identify generation limits? Please clarify that the intent is not to require constraints associated with non-firm transfers to be addressed.

15. R2.5.2: The addition of a transmission line always helps plant stability. Therefore, this should not be included as a change requiring a new study.

16. R2.7.1.1 requires that the action plan include a project initiation date as well as the in-service date. The project "initiation date" is not defined and can be interpreted as being when you thought up the project, when you started spending money on design, or when you actually started construction. As long as you have the in-service date when the project is needed, we do not see any major benefit from recording and documenting an "initiation" date. The length of time that it requires to complete a project is extremely variable based on many conditions so we're not sure what benefit, if any, will be gained by recording and documenting the initiation date. It may be impossible for someone not familiar with the legal, regulatory, etc. requirements in a given area to judge whether the timing is appropriate or not. This requirement should be eliminated.

17. R2.7.5 calls for the review of the implementation status of facilities. This imposes a large documentation requirement which has no benefit in reliability. We suggest making this requirement on an "as requested" basis.

18. Requirements 3.2 and 4.2: Delete the words "including those" so that it reads "the removal of all elements that System protection is expected...". As currently written, it sounds like you are going to remove more elements than the protection will remove.

19. R3.2 requires that the contingency analysis shall simulate the removal of all elements including those that System protection is expected to disconnect for each contingency without operator intervention. At present most steady state analysis uses

single "element" contingency with element defined as transmission lines or transformers as defined in the Power Flow cases. In a significant number of cases these individual "lines" are part of a larger "protection control group" (PCG). that would remove multiple elements encompased by the breakers in the PCG The present load flow tools (PSS/E) do not have features that will allow this type of analysis in an automated manner. To facilitate this change in required analysis, program modification will be needed or additional programs written. For an example with a line from bus A to B and then B to C with breakers at A and C and load at B, the outage of either A to B or B to C with load service remaining at Bus B may produce a more stringent condition than removing A to B to C. It appears that the new requirement is requiring the A to B to C analysis instead of the more stringent A to B or B to C.

20. Requirement R3.2.1 is unclear. Generators generally have both a high and a low voltage limitation on the terminal voltage related to station service reqirements. Most load flow representations for generators tend to hold the voltage on the high side of the GSU instead of the low side. Is this requirement attempting to say that the voltage limitations on the generator terminals must be considered or is it something else? This should be made clear in the requirement.

21. R3.3.2.1 requires that the amount of "consequential Load loss following a single Contingency shall be identified and the anticipated duration be recorded". This is an arbitrary requirement that will require significant time and effort to document and will provide no useful information from a planning perspective. Also the inclusion of an "expected" duration is more arbitrary than the actual amount of load. The time required to restore the facilities is a pure guess at best since it will vary substantially based on circumstances and conditions. Since we are also required to remove all elements that the protection control group (PCG) will open instead of just a single "power flow model" line, some of the load may be restored during switching action for tapped loads and some may not. This creates an additonal confusion of what is required to be recorded in terms of duration and load reduction. We see no benefit from identifying and documenting either the amount of consequential load lost or the estimated duration that would justify the time and effort required.

22. R3.3.2.2 This states that curtailments of firm transfers are not permissible following single contingency events to meet the performance criteria. Please clarify whether "firm transfers" refers to firm point to point service only, or if firm network service is also included. Said another way, is the curtailment of a network resource permissible following single contingency events to meet the performance criteria? If not, please clarify how redispatch service as required by Order 890 should be considered. If curtailment of a network resource is permited, please clarify why curtailment of PTP would be held to a higher standard. Also, please clarify whether R3.3.2.2 applies to P6. Lastly, please clarify how Conditional Firm Service (CFS) as required by Order 890 should be considered in meeting R3.3.2.2. CFS allows the curtailment of "firm" PTP transfers. This appears to be in conflict with the performance criteria.

23. Requirement R3.6 is not clear. It could be interpreted as generator tripping allowed for multiple contingencies only for the situations that meet the "to be determined" conditions. Generator tripping should always be allowed for multiple contingencies.

24. R4.5 and R4.6: We suggest dropping the words "For the" in each of these.

25. R4.6.1: Plant stability studies should not be required for generating units as small as 20 MW. The threshhold should be 100 MW or greater.

26. R4.6.3: The last sentence "The identified Contingencies, at a minimum, shall be evaluated" is redundant because the requirement already says "shall be performed and evaluated" The last sentence should therefore be deleted.

TABLE 1 - STEADY STATE PERFORMANCE:

27. In Table 1 in the column titled "Interruption of Firm Transfer Allowed," does it pertain to point-to-point only, or does it also apply to network loads? Please explain how this provision is consistient with the requirement to re-dispatch to address system constraints.

28. Steady state table, extreme event description, section 3: Items d and f are operating issues and therefore should not be included in the table. Also, items c and d are identical. Items d and f are identical.

29. Steady state table: Add the requirement to study n-0 to the table so it will be complete. Call it P0.

30. Steady state table and stability table: Change the heading which now says "For all Planning Events" to say "The following performance requirements must be met for the Planning events evaluated in addition to the requirements given in the columns"

31. Steady state table: For the event in P3, it is not clear what the "above 300 kV" applies to. Is it only the transformer? Or it it also the transmission circuit and generator? Also, the third column mentions DC when there is no DC in the event.

32. The event description in P3 is confusing. Please consider rewording in the 1,2,3 format of the other event descriptions. The term "non-bus tie breaker" is confusing. Please consider using "breaker (excluding bus ties)". Also, above 300 kV, most construction is either ring bus or breaker and a half. Please considered deleting the bus outage contingency. Lastly, please clarify how redispatch and CFS should be considered in the context of P3 and P4, in which the curtailment of firm transfers is not permissible to meet the performance criteria.

33. Steady state table: For transformers below 300 kV, P9.6 is no different from P8.3. We suggest adding the clarification of "above 300 kV" for P9.6.

34. Steady state table Extreme Event:
3.b "A successful cyber attack" needs to be clarified. What should the contingency be?
3.g Add the words "As applicable" to the beginning.
3.h This should be changed to "Other events as deemed appropriate by the PC based upon operating experience". Otherwise there will be no end to the contingencies that must be studied.

35. Several events in the tables use the term "internal fault" for a breaker. The SDT needs to explain what is intended by this term.

36. Steady State Performance Requirement, Table 1, Performance Levels P1-P4, should allow for the interruption of firm transfers if the transfer is dependent upon on the outaged equipment (whether AC or DC) to provide an electrical path specified in the transfer. Therefore, the current verbiage used for the outage of a DC Line should be applied to all levels and state, “Yes, if transfer is dependent on the outaged equipment to provide an electrical path for service”

37. Steady state and stability tables: in the Extreme Events section heading, the word "all" implies that all events must be evaluated when this is not the intent. Either make the heading "For Extreme events" or make it "For all Extreme Events evaluated".

TABLE 2 - STABILITY PERFORMANCE TABLE:

38. Stability table, note 1.a.i: P3.2 should be P2.3.

39. Several events in the tables use the term "internal fault" for a breaker. The SDT needs to explain what is intended by this term.

40. In event P7.2, does the "below 300 kV" apply to the generator, transmission circuit, transformer, and bus as well as to the stuck breaker? Or does it apply only to the stuck breaker?

41. The event description in P3 is confusing. Please consider rewording in the 1,2,3 format of the other event descriptions. The term "non-bus tie breaker" is confusing. Please consider using "breaker (excluding bus ties)". Also, above 300 kV, most construction is either ring bus or breaker and a half. Please considered deleting the bus outage contingency. Lastly, please clarify how redispatch and CFS should be considered in the context of P3 and P4, in which the curtailment of firm transfers is not permissible to meet the performance criteria.

42. Steady state table and stability table: Change the heading which now says "For all Planning Events" to say "The following performance requirements must be met for the Planning events evaluated in addition to the requirements given in the columns"

43. Steady state and stability tables: in the Extreme Events section heading, the word "all" implies that all events must be evaluated when this is not the intent. Either make the heading "For Extreme events" or make it "For all Extreme Events evaluated".

44. Stability table, footnote 1.a.ii. After "out-of-step protection", add the words "or some other means to trip the generator for this condition".

GENERAL:

45. The overall level of documentation required by this standard is excessive.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Scott Helyer	
Organization:	Tenaska, Inc.	
Telephone:	817-462-1512	
E-mail:	shelyer@tnsk.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☒ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☒ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☒	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☒ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: Using consequential and non-consequential seem to be misleading. Perhaps using "direct" and "indirect". Also, mis-operation needs some more explanation and to why it should be included here.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: I think most people understand, but in this new world we need to put some more specificity around the words "low probability".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: See Q2 answer.**	

Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: May be best to stop the definition after the word assumptions and cover the details as part of the requirements in the standard itself.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Not convinced that this study needs to be differentiated from a System Stability Study.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment: A generator's loss of synchronism and oscillation issues will be seen in this study.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☒ No ☐

Comment: The question may be misleading as number of sensitivity cases is not the issue. Enough studies should be conducted to appropriately define the boundaries of how the system will perform. The standard identifies various issues that may be used as sensitivity cases, but the list may or may not be all inclusive. The team should ask the industry whether any other sensitivities should be included in the standard.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☒ No ☐

Comment: However, what is meant by "reasonably stressed".

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐

Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☒

Comment: Any analysis that is performed needs to include some sort of sensitivity analysis. In fact, the sensitivity analysis may yield more information that is helpful in making decisions today than sensitivities performed on a near term study. A way of conducting a sensitivity analysis for long term studies may be to require long term studies to be performed for several years instead of only the one year that is required in the 6-10 year horizon.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system

deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: While DSM may, or may not, be manually operated, it is critical to understand the impacts of DSM and whether different ways of implementing DSM are of value.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: The study area should be the same as in the original study unless the Corrective Action Plans require changes/additions outside of the original study area. If chagnes/additions are made outisde the original area, then the study area must be expanded to include, at a minimum, the area that includes the new changes/additions.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: Add after the word "requirements" the following: "without the committed projects."

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	May need to consider using 500 kV as some transmission providers serve load off of the 345 kV system which could be triggered by this event.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	See comment in Q20.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	See comment in Q20.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	See comment in Q20.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: Why should we distinquish between a bustie breaker and a non-bus tie breaker? Also, 300 kV may be too low. This is really an issue that should be driven by the customers.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: This is really an issue that should be driven by the customers.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	This is really an issue that should be driven by the customers
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	This is really an issue that should be driven by the customers
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	This is really an issue that should be driven by the customers
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	This is really an issue that should be driven by the customers

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

[1] System adjustment can be manual or automatic

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment:

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☐ No ☒
Comment: The same set of contingency tests need to be applied to in both steady state and stability studies. The performance levels may need to be characterized a little differently, but at the end of the day we are trying maintain a reliable system for the same initiating event both in a stability timeframe and a steady state timeframe.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: It is not clear that there is any difference between the two studies.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Only on a case by case basis where a common mode/single point of failure can be identified that results in the loss of an entire plant.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Any adjustment(manual, automatic, runback, tripping) should be allowed as long as the performance requirements are achieved as described in standard after the adjustments have been made.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: So long as the performance requirements are met then this is not an issue.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: The system, following the use of an RAS or SPS in response to a single contingency, shall meet the performance requirements.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: The system, following the use of an RAS or SPS in response to a single contingency, shall meet the performance requirements.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: The proposed standard contains a number of areas that need further definition, more explanation, or more specificity.

For example, requirement R1 should be rewritten as follows to make it clear who has responsibility for each requirement AND sub-requirement as the standard as written could be read to imply that Transimssion Owners and Generation Owners have to supply a load forecast to the Planning Coordinator:

R1. Each Resource Planner, Transmission Planner, Transmission Owner, Generator Owner, and Load-Serving Entity shall each provide, as specified below, its respective Planning Coordinator with the following modeling information required for System performance studies upon request (within 30 calendar days) : [Violation Risk Factor: TBD] [Time Horizon: TBD]

R1.1. Each Load Serving Entity shall provide the Planning Coordinator load forecasts adhering, at a minimum, to the following criteria:
R1.1.1. Use of expected Load mix based on the actual or expected aggregate mix of industrial, commercial, and residential Loads.
R1.1.2. Based on normal weather patterns as agreed to by the Planning Coordinator(s) and the Transmission Planner(s) for the area(s) of their responsibility.
R1.1.3. Identification of Demand Side Management (DSM) Load reductions consistent with operational requirements.

R1.2. Each Load Serving Entity shall provide the Planning Coordinator load models with supporting rationale that include power factor data based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements.
R1.3. Each Load-Serving Entity shall provide the Planning Coordinator the Firm transfers/Interchange Schedules and resources required to supply Load for each Balancing Authority.
R1.4. Each Transmission Owner and Generation Owner shall provide the Planning Coordinator with known planned outages and long-term outages for Transmission and Generation equipment including protective relays with consideration given to spare equipment strategy.
R1.5. Each Transmission Owner, Generation Owner, Resource Planner, and Transimssion Planner shall provide known planned Facilities defined in accordance with the documented criteria of the Planning Coordinator, including but not limited to: Transmission Lines, generators, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies.

The above is an example and I apologize for the poor pagination. However, the drafting team should look at each requirement/sub-requirement and specifiy precisely to which entity the requirement/sub-requirement applies.

Other comments/concerns/questions with the proposed standard:

Does requirement R2 mean that you you could have two assessments: one performed by the Transmission Planner and one performed by the Planning Coordinator? This could result in two assessments of the same facilities which may or may not be desired.

In Requirement 2.5.1, what is meant by increasing generation? Is there a minimum amount of increased generation or is it any increase?

In Requirements 2.5.2, 2.6.1, 2.6.2, and 2.6.3, what is meant by "material"? This needs more definition wherever the word "material" is used throughout the standard.

In Requirements 2.6.1, 2.6.2, and 2.6.3, the word System and system are both used. Whose System or system needs to be defined. Does that include neighboring system(s)?

In Requirement 2.7.3, "committed" and "proposed" need to be defined.

In Requirement 2.7.5, what needs to happen as a result of such review? Is something supposed to happen in the Corrective Action Plans depending on the implemenation status of identified System Facilities and Operating Procedures?

In R3, what is "normal" performance (n-0)? Should this be a defined term?

In R3.2.1 and 3.2.2, why are these issues covered in a TPL standard as it seems to be more applicable to the Facility Ratings standards or the MOD10, 11, 12, and 13 standards? The TPL standard should probably reference these other standards for issues associated with ratings.

In R3.3.2, the reference to "single contingency" should reference the category (P1, P@, P#, etc.) in Table 1.

In R3.3.2.2, the term "firm transfers" needs to be defined.

In R3.3.3 and R3.4, reference is made to "expected to produce more servere System impacts." How does somebody determine what extreme events that are "expected to produce more servere System impacts?"

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

<table>
<tr><th colspan="3">Individual Commenter Information
(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td>Name:</td><td colspan="2">David Till</td></tr>
<tr><td>Organization:</td><td colspan="2">Tennessee Valley Authority</td></tr>
<tr><td>Telephone:</td><td colspan="2">423-751-7147</td></tr>
<tr><td>E-mail:</td><td colspan="2">bdtill@tva.gov</td></tr>
<tr><td>NERC Region (check all Regions in which your company operates)</td><td></td><td>Registered Ballot Body Segment (check all industry segments in which your company is registered)</td></tr>
<tr><td rowspan="10">☐ ERCOT
☐ FRCC
☐ MRO
☐ NPCC
☐ RFC
☒ SERC
☐ SPP
☐ WECC
☐ NA – Not Applicable</td><td>☒</td><td>1 — Transmission Owners</td></tr>
<tr><td>☐</td><td>2 — RTOs and ISOs</td></tr>
<tr><td>☐</td><td>3 — Load-serving Entities</td></tr>
<tr><td>☐</td><td>4 — Transmission-dependent Utilities</td></tr>
<tr><td>☐</td><td>5 — Electric Generators</td></tr>
<tr><td>☐</td><td>6 — Electricity Brokers, Aggregators, and Marketers</td></tr>
<tr><td>☐</td><td>7 — Large Electricity End Users</td></tr>
<tr><td>☐</td><td>8 — Small Electricity End Users</td></tr>
<tr><td>☐</td><td>9 — Federal, State, Provincial Regulatory or other Government Entities</td></tr>
<tr><td>☐</td><td>10 — Regional Reliability Organizations and Regional Entities</td></tr>
</table>

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☐Agree. ☒Do not agree.
Q2. **Comment: We recommend that the terms consequential and non-consequential be changed to direct and indirect. Also, the term should be better defined. We recommend that the definition be "loads that have been de-energized by fault-clearing action or loads that are lost even though the system performance remains within acceptable limits."**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: A number of the planning events also have a low probability. The definition for "Extreme Events" should reference Table 1.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding,	☐Agree. ☒Do not agree.

or Special Protection Systems.	
Q6. **Comment: See comment for Q2. We recommend that this term is defined as "load loss other than consequential load loss".**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Use of the word "deficiencies" instead of "needs" provides better consistency throughout the standard. We do not agree that the planning assessment should directly include asset conditions and age. Asset condition should be part of the ratings process. The age of equipment, if it is well maintained, has little impact on reliability.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☒Agree. ☐Do not agree.
Q9. **Comment:**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: The last sentence in the above definition was not included in the definition listed in the draft standard, nor should it be.**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the

requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: The entity performing the studies should be allowed to determine the appropriate number of cases that need to be evaluated.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: The standard may offer guidance but what constitutes a "reasonably stressed" case should be left to the discretion of the entity performing the study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment: Consideration should be given to the fact that stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment:

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This

Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: It should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is considered firm. However, the standards should not determine which type of fix a utility should use to meet system requirements.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐

Comment: Re-testing should be required only where the correction may impact network flows. For example, a transmission line re-sag or CT ratio change to increase a facility rating should not require re-testing. The study area should be determined by the TP or PC as appropriate. The TP or PC has the most knowledge of how the system responds to changes.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐

Comment:

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐

Comment:

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to

clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	By not allowing non-consequential load loss, utilities will incur significant expenditures to construct a transmission solution for some extremely low probability events with low consequence. Each utility should have the flexibility to base action on probability and consequence. Load shed by UVLS or other means should remain an option to maintain reliability if probability is extremely low, but the high consequence of an event determines that a solution is necessary.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	See Q20.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage	☐Agree. ☒Do not agree.	See Q20.

rating above 300 kV		
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	See Q20.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: See Q20.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: See Q20.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	It is agreed that this event should be tested for maintaining reliability of the BES, however planned load loss should be allowed.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	It is agreed that this event should be tested for maintaining reliability of the BES, however planned load loss should be allowed.
Q28. P4-3: Loss of a generator followed by System adjustment followed	☐Agree. ☒Do not agree.	It is agreed that this event should be tested for maintaining reliability of the BES, however planned load loss should

[1] System adjustment can be manual or automatic

by loss of a Transmission circuit		be allowed.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	It is agreed that this event should be tested for maintaining reliability of the BES, however planned load loss should be allowed.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: There are also conditions where this interruption should be allowed for a single AC tie line.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: This question conflicts with Table 2 Extreme Event #9.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load

model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐

Comment: Dynamic studies of seasonal load conditions should include the effects of induction motors, and particularly in areas where traditional load models have indicated a problem. Unfortunately, there is a lack of data to support the amount and characteristics of the detailed induction load models in many areas. In addition to the consideration of the dynamic effects of induction motor loads, the effects of static capacitor banks installed at distribution voltage levels would need to be considered as well. Prior to making this a requirement in the reliability standards, the industry needs guidance as to how this data should be developed and maintained for models in future years. Also, the existing software capability is extremely limited in the ability to study the effects of motor loads.

Note that meeting such a requirement would necessitate a significant increase in the dynamic data needed to represent the system. Maintenance of such load model data would require significant resources. Load characteristics valid for a near term model might not be valid for future years. Also, summer peak load, winter peak load, and off-peak load characteristics would differ.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Any adjustments should be allowed that protects the reliability of the BES.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: The generator runback scheme should complete its action within the time allowed by the emergency ratings of elements that exceed their normal thermal ratings.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☒
Comment: TVA does not allow generator tripping for a single contingency. However, we recognize that there are certain instances for which this makes practical and economic sense.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: RAS or SPS should meet the same criteria as any protection system.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: The conditions required by SPS standards (PRC).

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☐
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: Requirement R1 does not belong in this standard. These requirements are covered by MOD standards.

Spare equipment strategy should be covered as a sensitivity study, but not included in the base case.

R2.1.1 should not be so prescriptive as to which years of 1-5 are studied.

The wording for R2.1.3 and R2.4.3 should be consistent.

Consideration should be given to the specific phases which are faulted in the simultaneous faults for P9 of the stability table. The results can be much different if the simultaneous faults occur on the same phase or different phases.

More guidance should be given for the term "Interruption of Firm Transfer Allowed" in Table 1. Firm transfer is not defined in the NERC glossary. The type of transmission service should be outlined here.

R2.7.1.1 - The project initiation date is not relevant in a reliability standard.

Extreme Event Descriptions
2. a. and b. should include mileage threshholds.
3. e. The term "large load" is vague and should be clarified.
   d. and f. are duplicates.
   c. and e. are duplicates.

Minimum generator voltage data required for R3.2.1 will be require extensive and costly generator testing and analysis to provide data necessary for transmission system studies.

R3.3.2.1 is an operational issue rather than a planning issue.

The addition of the "Corrective Action Plan" requires the TP to provide a significant amount of documentation for each deficiency identified by the studies.

Also, R3.2 requires that the studies simulate the protection scheme for all events. The current software tools cannot automate these studies for bus faults and breaker failure events, requiring each scenario to be studied manually.

The planning event designations are confusing because both the steady-state and stability tables have events P1-P9. A different designation should be used for one of the tables.

In R4.6 and other locations, the individual generator exemption of 20 MW should be increased to 75 MVA.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Alex Boutsioulis	
Organization:	The United Illuminating Company	
Telephone:	203-926-4630	
E-mail:	alex.boutsioulis@uinet.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ ERCOT	☒	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs and ISOs
☐ MRO	☐	3 — Load-serving Entities
☒ NPCC	☐	4 — Transmission-dependent Utilities
☐ RFC	☐	5 — Electric Generators
☐ SERC	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ SPP	☐	7 — Large Electricity End Users
☐ WECC	☐	8 — Small Electricity End Users
☐ NA – Not Applicable	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☐Agree. ☒Do not agree.
Q1. **Comment: There are a few undefined terms in this definition: "Transmission System" and "interconnected Transmission System". The definition needs to specifically identify what should be modeled and in a manner consistent with other NERC definitions. The definition refers to Facility ratings rather than the general reference to FAC-008 & FAC-009**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: Modify to "Events which are more severe,but have a lower probability of occurrence, than Planning Events".**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☒Do not agree.
Q4. **Comment: "Transmission planning period that covers years six through ten", is sufficient for the standard." Suggest changing the name to Long-Term Planning Assessment.**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment: Suggest changing the name to Near-Term Planning Assessment.**	
Q6. **Non-Consequential Load Loss:** Load loss other than	☒Agree.

Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Do not agree.
Q6. **Comment:**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☒Do not agree.
Q7. **Comment: Eliminate "capital" from the definition. It is not defined or consistently applicable to the standard. Reference to vague "other factors, such as asset conditions and age" should be removed from this standard; there are no consistent definitions or industry standards on which to base this requirement, nor does it appear to be a necessary addition to the standard.**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☒Do not agree.
Q8. **Comment: Propose, "Events for which Transmission performance requirements must be met".**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☒Do not agree.
Q10. **Comment: See comment on Q9; proposed modification, "Study of the System or portions of the System to determine whether unit and system angular Stability is maintained, power oscillations are damped, and voltages during the dynamic simulation stay within acceptable perfomance limits.**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: Modify to, "The first year that a Tranmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner completes its annual studies."**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement to develop action plans for problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System shall be considered, and documentation with the rationale for the sensitivity testing shall be supplied. The sensitivity case(s) may include one or more of the following conditions:"

2.1.3.3 should refer only to planned facilities that may be delayed. 2.1.3.4 - "variability" is too vague for a standard; the standard needs to be more specific as to the intent. 2.1.3.7 should be consistent with 1.4. These comments also apply to 2.4.3.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: The standard is unclear whether or not it mandates the requirement develop action plans for problems highlighted as a result of one of the sensitivities.

Reasonably stressed conditions are dependent upon the study area under review and the standard is not likely to be able to be crafted to provide sufficent and consistent direction. However, it might be helpful if the standard clarified whether the base case should include any unplanned generator outages or whether, aside from potential sensitivities, unplanned generator outages are considered only through P1, P3 or P4 Contingencies. If the standard addresses unplanned generator outages only through P1, P3 and P4, then it is recommended that a mandatory sensitivity analysis, with required mitigation, include various potential combinations of a reasonable amount of unplanned outages. The combinations should be based on the part of the system that is under study.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐

Comment: The standard is unclear whether or not it mandates the requirement to devleop action plans for problems highlighted as a result of one of the sensitivities.

Suggest modification to, "…sensitivity testing that stresses the System should be considered. Sensitivity case(s) might include among the following conditions:" 2.4.3 shold mimic 2.1.3 except in regard to load models.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: There is no need for sensitivity analysis.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐

Comment: DSM should be included to the extent that its performance is sufficiently and consistently understood. The standard does not use the term "optimal" Therefore, the Drafting Team appears to be interpreting the Standard to require a vertically-integrated Planner to produce a so-called optimal-mix of resources plan. This would be an incorrect assumption and is not required. In areas with independent planners and competitive wholesale markets, it is sufficent to identify system needs and produce a plan that identifies regulated transmission solutions in the event that market-based resources (such as DSM) do not address those identified needs. Therefore, while DSM can be as effective a resource as generation, per Commission Orders,

in areas with ISOs/RTOs and a competitive wholesale market, the NERC Standard cannot prescribe the development so-called optimized (as is suggesgted by the Drafting Team) resource-mix plans, as identified by a central planner.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: The study area should be based upon planning expertise and knowledge of the system, giving due consideration to external impacts.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☐
Comment: They should be viewed differently in the Near-Term. However, these should be defined terms.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: It is unclear as to what the commited project is being removed from. Suggested language "…removed from the plan…".

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☒Agree. ☐Do not agree.	
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	Given the low probability of extended overlapping outages of overhead facilities, systems have been designed assuming that load shedding following the loss of a second transmission line is permissible. Eliminating any allowance for load shedding for this condition may require significant system expansion and cost to to customers. However, it would be reasonable to consider establishing an upper bound to the amount of load that could be shed for these purposes.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	Should also consider the initial loss of a transformer, followed by the loss of a Transmission circuit. This should state a transformer with a "high-side" rating above 300 kV.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	This should state a transformer with a "high-side" rating above 300 kV.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☒ No ☐
Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of 2 additional generators.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a monopolar DC line
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a Transmission circuit
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☐Agree. ☒Do not agree.	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a transformer

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm

[1] System adjustment can be manual or automatic

transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment: This should also apply to firm transfers via single or double ac facilities as well. In either case, the transfer could be linked to dedicated facilities.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: Difficult to envision how such an event would occur.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☐ No ☒
Comment: This requirement is too specific and limited. Induction motors are only one component of a complex load model. Complex load models are not always necessary, nor are they always the most conservative, depending on the analysis that is being conducted. Where complex load models are required, they should be considered; this may involve use of complex motor and lighting loads or polynomial load representations

with or without frequency dependence. This question also suggests the need for an industry standard regarding transient voltage recovery.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: Manual or automatic adjustments should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment. Manual system adjustment should be allowed in between the multiple Contingencies described in P5, provided that the adjustment can be made between contingencies using short-term reserves (10-30 minute).

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment: Generation runback should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐

Comment: However, this should only be allowed where failure of an automatic runback that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: Only allowed where the failure of an SPS that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Only allowed where SPS failure would not have significant adverse impact on the Bulk Electric System; non-Consequential loss of load should be allowed up to an amount potentially specified in the standard.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: System must remain stable with acceptable voltages and all equipment within applicable emergency limits.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☒
Comment: Unsure due to ambiguities in the standard. Depending upon the final standard, New England may need exceptions for existing facilities or allowance for a transition period to develop a compliance plan.

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: There should be a "P0" standard that applies to system performance without any contingencies.

Standard should be clear that stabiltiy analysis is not required for Long-Term Planning Assessment.

R.1.1 Load forecasts should be addressed in MOD standards, not TPL.

R 1.4 This should only refer to known long-term outages, not planned outages. Delete "including protective relays"; this is addressed through other provisions.

R.2.1 Shorten "Near-Term Transmission Planning Horizon Planning Assessment" to "Near-Term Planning Assessment".

R 2.2 Shorten "Long-Term Transmission Planning Horizon Planning Assessment" to "Long-Term Planning Assessment".

R2.1, 2.2, 2.3 & 2.4 – The initial paragraph should have identical language regarding ‘annual’, and ‘current or past’ aspects.

R2.1.1 There should not be a requirement to look at years one and two; a 5 year study should be sufficient. If there has been an ongoing 5 year study, there should be no major unexpected problems occurring in years 1 and 2. Studies of earlier years should only be required if an unanticipated event occurred that had not been considered in prior studies. The TPL should not address shorter term "Operating Studies" or operating issues.

R 2.2.1 Modify to "If any known projects have a lead time that is longer than ten years, the Planning Assessment shall be extended accordingly."

R 2.6 Steady-state, short circuit, and stability analysis should be required no more than every 5 years unless there is a significant change the system.

R 2.6.1 Remove reference to "market structure changes". The purpose of it's inclusion is unclear.

R 2.7.1.1 Project initiation date should be deleted. If it is retainted, it needs to be defined.

R 2.7.3 Committed and Proposed projects should be defined.

R 3.2.1/R 4.3 - What is the intent of this requirement? There should probably be an MOD associated with Generator Owner requirement to provide related generator protection/ limiter data or other plant information.

R 3.4/R 4.5.2 Remove the requirement to implement changes to reduce or mitigate the likelihood of such consequences of Extreme Events. This may not be reasonable or achieveable.

R 3.2 Sectionalizing schemes shall be considered when reflecting the post-contingent system.

R 3.2.2 - Propose deleting this. Line ratings should already take relay loadability into account.

R 3.3.2.1 - Proposed deleting "expected duration". This would be dependent upon the damage to the element due to the iniating event and other factors.

R 3.3.2.2 - The requirements of this section do not match P6.

R 3.3.3 - Change introductory language to read "Those multiple Contingencies that are…"

R 3.5 - Generation tripping should be allowed as well as generation run-back. In addition, all performance requirements shall be met, rather than just meeting facility rating requirements. Suggested lanague "Manual and automatic generation run-back and/or generation tripping is allowed as a response to single and multiple Contingencies as long as the performance requirements of this standard are met." If these changes are accepted, R 3.6 can be deleted.

R 4 and R 4.1 - The language should be made similar to R 3 and R 3.1.

Suggest bringing language similar R4.4 into the R 3, the steady state section.

R 4.2 - High speed automatic reclosing schemes shall be considered.

R 6.3 - Change to read "Planning Coordinators of neighboring impacted areas".

Table 1 3 b and c Extreme Event descriptions are vague concepts that cannot be practically simulated. 3 d and e are not reasonable or practically useful to simulate.

Table 1, P8 - Language needs to be clarifed as to how the 300 kV threshold is to be treated for transformers. Is this for the high side, low side, or both sides? P5 is much clearer.

Table 2 - Clarification needs to be made that the faults being simulated are permanent faults. This can be addressed under the "Performance Requirements" portion at the beginning of the table, or modify each fault description.

Table 2 P9. Recommend that this be changed to require that faults should be on different phases of each of two adjacent transmission circuits on a multiple circuit transmission tower

Table 1, P9(6) and Table 2 P9 - It is unclear as to what is meant by "A spare transformer inserted to replace an outaged transformer followed by System adjustments". Unclear as to what is to be tested.

General comment - Transmission System is used throughout the document and is an undefined term

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Mark Graham	
Organization:	Tri-State Generation and Transmission Association	
Telephone:	303-452-6111	
E-mail:	mgraham@tristategt.org	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☒ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☒Do not agree.
Q1. **Comment: same as WECC group comments**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☒Do not agree.
Q2. **Comment: same as WECC group comments**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☒Do not agree.
Q3. **Comment: same as WECC group comments.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: same as WECC group comments**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time	☒Agree. ☒Do not

frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	agree.
Q7. **Comment: same as WECC group comments**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Plant stability should be called Station stability. The term "plant" is reserved for aggregates such as total coal plant or total peaking plant, meaning all generating units in that category.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.

- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒
Comment: same as WECC group comments

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒
Comment: same as WECC group comments

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☐ No ☒
Comment: Sensitivity studies are most often used to determine operating relationships of a system - sensitivity to generation patterns is deliverability analysis; sensitivity to load growth is margin analysis. Sensitivity analysis should not be required explicitly. The criteria should be stated in terms of load margins, deliverability, and capability to withstand generator or transaction forced outages. The TP can use sensitivity studies or other reasonable methods to assess reliability

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☐ No ☒
Comment: It is just as important for long range plans of service to provide acceptable operation as it is for near-term facility plans. To specify different criteria for different time periods seems unreasonable.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or

Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☐ No ☒
Comment: DSM should not be considered except as a load forecast variable. Rather, the load forecast probability index should be prescribed (specific probability of exceedance)

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒
Comment: same as WECC group comments

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: same as WECC group comments

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: R2.7.4 calls for change monitoring. If documentation of changes is required, just say so. Do not restrict changes.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material

changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	same as WECC group comments
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	same as WECC group comments
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	same as WECC group comments
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	same as WECC group comments

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒
Comment: same as WECC group comments

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒
Comment: same as WECC group comments

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	same as WECC group comments
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	same as WECC group comments
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	same as WECC group comments
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	same as WECC group comments

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☒
Comment: same as WECC group comments

E. Stability

[1] System adjustment can be manual or automatic

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☒
Comment: same as WECC group comments

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒
Comment: same as WECC group comments

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒
Comment: same as WECC group comments

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☒
Comment: same as WECC group comments

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: same as WECC group comments

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: same as WECC group comments

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: same as WECC group comments

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: same as WECC group comments

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐

Comment: same as WECC group comments

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☒ No ☐
Comment: same as WECC group comments

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: R1 and R2 address some Load Forecast issues, but are not exhaustive specifications of what Load Forecast range to use in studies. There needs to be some mention of exceedance probability (ExPr) in Load Forecast criteria. For example, we use a forecast with a low ExPr in our studies because we are concerned that, if the system was planned for 50% ExPr (a lower forecast), actual deviation from that forecast might result in load at certain locations exceeding operating margins built into the interconnected transmission system designed to serve only the 50% ExPr forecast load.

Load Specifications in R2.4 are ambiguous for the reasons stated above.

Maximum study ages in R2.6.1 and R2.6.2 seem arbitrary. The time limit does not seem to add anything to the criteria if no material changes have occurred. If spot checks of the most critical areas indicated no criteria violations, there should be no reason to rerun studies. To correct this problem, we suggest using the term “assessment” rather than “study”. For most people, “study” implies detailed modeling and simulation analyses summarized in a report, whereas “assessment” implies a reasonable, systematic evaluation of a system which does not necessarily include detailed analysis for the entire system.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Gary Trent	
Organization:	Tucson Electric Power Company	
Telephone:	(520) 745-3168	
E-mail:	gtrent@tep.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	Agree or Disagree
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☒Do not agree.
Q1. **Comment: A Base Case can only represent the amount of transactions required to serve connected load modeled in the case (local load?). A Path Rating case (developed to represent maximum transfers on a path) would not be considered a base case under this definition. WECC develops base cases to study high power transfers under stressed conditions. Such high power transfers necessarily include both firm and non-firm transaction obligations. Therefore, a base case that represents firm transactions to support “connected load” only, cannot be used to support studies of maximum possible power transfer and is of limited value in WECC. We agree that the above definition is one definition of a base case, but we feel that it can not be the only definition or the limiting definition. We suggest that wording be included that reflects the concept of modeling forecasted or above forecasted load levels if desired, and both firm and non-firm transactions if necessary to model anticipated maximum transfers and represent stressed system conditions as well.** **The definition should refer to the base case as a Computer Simulation Model of the power system, not a Computer Representation of the transmission system, since it is used within a computer program and represents load and generation in addition to transmission. References to “the generation dispatch and firm transaction obligations to supply the connected load” should be removed.** **A base case is a starting case for any condition that needs to be studied, not just a firm transactions case. Firm obligations across the transmission system are many times independent of a specific load service obligation.**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☒Do not agree.

Q2. **Comment: Agree with the definition in concept. However, the wording makes the definition seem unrealistic. There are many examples where a certain amount of voltage sensitive load or motor drives sensitive to angle changes are dropped due to normally cleared electrical faults on the transmission system. These loads are not directly connected to the element being removed from service. This type of sympathetic loss of load is unique to the individual customer load. The design of these loads is not under the control of the utilities when it comes to ability to ride through normally cleared faults. We suggest that this definition be modified to include the loss of sensitive load that is not directly connected to the element being removed.** **We propose the following the definition : Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation, and because of sympathetic tripping associated with normal clearing or mis-operation. Load that is lost because it trips due to low voltages experienced during and immediately following the fault (4-6 cycles?) is also considered consequential load loss. We believe this additional recognition is needed because load lost due to low fault voltages is unavoidable and should not result in a standard violation.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☒Do not agree.
Q3. **Comment: Please add the phrase "two or more elements out of service" to the definition from the previous definition in Table I.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: Please add "or Remedial Action schemes" to the end of the definition. FERC Order 693, paragraph 1773 states (6)"clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss." There needs to be a distinction made between Interruptible Load and Firm Demand.**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions	☒Agree. ☒Do not agree.

and age.	
Q7. **Comment: As identified by the modifications above, we believe the definition should be changed to read, "Documented evaluation of future Bulk Electric System needs by the use of performance studies (steady state and dynamic) that cover a range of reasonable or expected assumptions regarding system conditions, applicable time frames, and future plans; including capital reinforcements and operating procedures, SPS/RAS, and other factors (such as asset conditions and age)."**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Plant Stability seems to be a subset of System Stability. Introducing a new term can cause confusion.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The TP or PA is the most familiar with the system and so would be the best to determine the sensitivities that are more applicable to their particular system. The Standard should not be overly prescriptive. The Standard can make suggestions or list potential sensitivities but let the TP or PA determine those variables to study and the reasonable range of the sensitivities.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: No, as in the response for Question #12. The TP is the best to determine the type of stressing needed for a particular case. This is very evident in the type of cases used for studies in the different parts of the NERC regions.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☒

Comment: We concur with the use of sensitivities as long as the TPs are allowed to determine the sensitivities that are the more appropriate for their systems and not have the sensitivities scripted in the Standard.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: We agree with this conclusion. The Standard language should state that sensitivities are not required in Long-Term Transmission System Planning Horizon but the TP could use sensitivities if desired.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system

deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☒

Comment: It is unclear whether "DSM" in this question refers to reduction in load or increases in distributed resources, or if the resources are directly controllable by the transmission operator. DSM could be used in the mix of solutions that are used to determine the optimal solution for a transmission issue. However, we have concerns about the use of DSM, that is not under the direct control of the Transmission Operator as a stand alone transmission system solution. Please remember the overstated returns from DSM in the last decade that did not materialize. If these overstated values had been used as a transmission system enhancement, then the system would have been compromised with emergency operating solution until the effective transmission enhancements could be realized.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒

Comment: No, this is too onerous. We recognize that, when planning the system and developing a Corrective Action Plan, the transmission planner would have added the potential projects individually (or in small groups) into a case to re-test the system performance. Hoever, R2.7.2 seems to require that all potential projects be added back into the case simultaneously for retesting. There could be many different alternative solutions for each potential problem identified in the different study years without having the base solution first determined for a nearer term case. There can be many combinations of potential solutions for cases further into the future that satisfy the condition being studied. For example, a voltage problem can be solved by the addition of capacitors, completing a bus tie, adding a short line, operating procedure, changing generation dispatch, etc. Even assuming that one set of solutions are picked so the verification study can be performed, logistically this demonstration may be too close to the assessment in the following year. Instead of retesting the potential projects in the Corrective Action Plan on the original base case, it may be better to test them in the base cases prepared for following year's study. Any potential problem that is unresolved will show up again in the following year's assessment. Therefore, a separate demonstration using an "older" case may not be an efficient use of the TPs' and PAs' time and resources.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒

Comment: The definition of these terms can be vastly different across all TPs. How would this be effectively monitored for compliance with such different definitions? Also, each TO's criteria to go from a proposed project to a committed project can change over time due to other needs and requirements.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒

Comment: The requirement is similar to the question posed in Question 17. What is the documentation that proves this is needed?

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds

		of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds

		of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒

Comment: We disagree that non-consequential loss of load should not be permitted for this contingency event. We believe that planned and controlled interruption of non-consequential load should be permitted for loss of a non-bus tie breaker (above 300 kV). Losing a non-bus tie breaker could result in simultaneous loss of two or more elements, depending on the bus configuration. Allowing planned and controlled disconnection of some load in the areas would not only prevent cascading and instability (which could result in uncontrolled loss of a larger amount of load), but also enables faster load restoration. Losing a breaker due to an internal fault is a low probability event. To meet this requirement as proposed would require severe pre-contingency curtailment of power transfers, that could impact commerce and/or construction of large number of transmission facilities with the attendant environmental impacts and increased cost to customers.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: We disagree that non-consequential loss of load should not be permitted for this contingency event. We believe that planned and controlled interruption of non-consequential load should be permitted for loss of either a generator, a transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV). This contingency event could result in simultaneous loss of two or more elements, depending on the bus configuration. Allowing planned and controlled disconnection of some load in the areas would not only prevent cascading and instability (which could result in uncontrolled loss of a larger amount of load), but also enables faster load restoration. These contingencies are low-probability events. To meet this requirement as proposed would require severe pre-contingency curtailment of power transfers, that could impact commerce and/or construction of a large number of transmission facilities with the attendant environmental impacts and increased cost to customers.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping

[1] System adjustment can be manual or automatic

		outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☒
Comment: We agree with the question asked. In addition, transactions that can be interrupted due to the loss of a DC line should not be limited to the firm transactions, that are dependent on the DC line. It should also include interruptible transactions and other transactions made available through negotiated agreements on both AC and DC lines.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☒
Comment: We agree with the question asked. In addition, because of the time sequence from the start of the fault, through fault clearing and transient dynamic period, the post-transient period to the steady state post-contingency period, there needs to be clear links between the performance requirements in the transient

dynamic time period and the steady state time period. For example, if generator dropping or controlled load interruption is allowed in the transient dynamic period, it should also be allowed in the steady state time period that follows. Otherwise, it would put the Transmission Planners and the Planning Authorities in an untenable situation because, once a generator or load is dropped in the first few cycles after the disturbance; it cannot be required to be on line in the minutes that immediately follow.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒

Comment: It appears that Plant Stability Study is a subset of System Stability Study. R4.6.2 states these shall be performed for changes in real power output of a generating unit by more than 10%. Then it states they shall be performed for planning events. R4.5 already covers any contingencies that are an issue and the system already needs to meet some level of performance for loss of the generator. It seems that a change in generation would already be analyzed from a system standpoint as stated in R2.4.3. It appears that material changes to existing generators should be reflected in modeling requirements elsewhere.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment: We agree with the SDT that simultaneous 3-phase fault on all generating units in a plant is improbable and effort should be better spent studying more probable events. In any case, this Extreme Event is to be considered in the Steady State Table, and stability cases can be run if it is shown to be needed in the power flow study results. We are, however, confused by this question. This question states that the SDT did not include the requirement to consider loss of all generators at a plant in the stability, yet the Extreme Event in the stability table shows in No. 9, “3Ø fault with loss of all generating units at a station”.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☒

Comment: The requirement to include motor load should be extended to other load level periods and not be limited to peak load period only. However, to capture slow voltage recover phenomena, especially in areas of high penetration of refrigerated air conditioning load (e.g. 50% to 60%), would require modeling down to the distribution system voltage level and explicitly representing shunt capacitors and various induction motor types (e.g. equivalents for single phase motors). If the requirement is not extended, dynamic simulations will likely differ significantly from observed system events. We recommend a phase-in period so that the requirement for use of load models should only include regionally accepted load models for which data are available. This requirement can be extended or modified as the Region in which the entities reside adopts new load modeling guidelines.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: All adjustments should be allowed as long as they are realistic and achievable in the time frame required and consistent with other study parameters. For example, automatic adjustments would be required for correction of a stability problem, but manual adjustment should be allowed for correction of a thermal problem if there is no instability problem.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐

Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐

Comment: Yes. Agree. Conditions for generation run back for N-1: 1) Run back of generation cannot result in tripping of firm load, 2) power flow should be within the time-limited equipment ratings, 3) frequency should be within allowable limits.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐

Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Based on the interpretation of the above question, we are providing two responses to this question. The first responds to the limitations placed on RAS, regardless of what action the RAS initiates. The second response specifically addresses RAS that trips generation.

Response 1: RAS should be allowed for single contingency events. Any sort of RAS should be permitted, but there should be a review of the RAS. If the local entities agree to the RAS, it should be allowed. This addresses cost vs. benefit balance. Entities affected should be the ones that determine the best solution for their situation.

Response 2: Generation tripping can be used for single contingency if such application can be demonstrated through transmission planning studies that:

- The generation tripping is planned and controlled ("planned and controlled" means a pre-planned action(s) based on predetermined system conditions that take corrective measure(s) to maintain acceptable system performance).
- The generation tripping does not result in non-consequential load loss.
- System frequency should be within allowable limits.
- System voltage dip and deviation should be within allowable limits.
- The generator owner(s) agrees to the tripping as planned.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: System adjustment involves operator intervention that would be beyond the time frame of RAS operation. Therefore, if a unit is already dropped during RAS or SPS action, it should be assumed to be off-line during system adjustment period.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐

Comment: Yes. WECC allows tripping of generators to meet single contingency performance requirements. WECC also allows planned and controlled load shedding for the proposed Planning Events P2-1, P2-2, P3, P4 and P5, although we agree with the proposed requirements for P4 due to the higher probability of occurrence. If the standard does not allow for non-consequential load shedding of 300 kV and above for P5 scenarios, WECC will develop a regional variance".

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☒ No ☐

Comment: 1) FERC Order 693, Paragraph 1825 regarding TPL-003, Category C – The Commission directed the ERO to modify footnote (c) to Table 1 to clarify the term “controlled load interruption” rather than eliminate its applicability to this performance requirement. 2) FAC-010-1, R2.3 – “…planned or controlled interruption…” This conflicts with “No” for non-consequential load loss allowed in draft TPL.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment: 1. R1.3 requires the provision of firm transfer/Interchange Schedules and resources required to supply load for each Balancing Authority. It may not be possible to have reasonably accurate information on firm transfers and Interchange Schedules for years into the future. Within WECC, we develop base cases that represent reasonably stressed conditions that model power flows stressing various paths. Therefore, within WECC, we design the system to operate at levels that can support all sorts of commerce, including the effects of loop flow, and firm and non-firm contracts, in addition to other possibilities. It would be difficult to develop information from this mixture that includes only firm transactions for such future base cases. In addition, WECC does not allow operations at levels not previously studied. Therefore, an exercise to determine firm transaction/schedules would produce information that will be of little value to support reliability in WECC.

2. R2.7.1.2 requires identification of system deficiencies and accociated corrective action for the Long Term Transmission Planning Horizon. This requirement needs to tie to the lead times to implement the corrective action(s). For example, if a 500 kV transmission line is needed to correct a deficiency that surfaces in the tenth year, then this requirement is reasonable. However, if the deficiency is on a low voltage system, that can be resolved with short lead-time projects (such as installing a small capacitor bank) then this requirement would seem to be too prescriptive.

3. R1.5 requires providing modeling information as part of R1 on a number of transmission planned facilities, including circuit breakers. Since circuit breakers are part of a transmission line, we are not sure how a circuit breaker would be modeled separately, as required.

4. R3.2.1 requires that "studies shall consider the minimum steady state voltage limitations of all generators". Since generators (as well as other facilities) have both high and low voltage limits, the standard should require consideration of both high and low voltage limits.

5. In R.3.2.2, please provide a reference for relay loadability.

6. R.3.3.2.1. requires that Consequential Load loss (expected maximum demand and expected duration) following a single contingency shall be identified in the Planning Assessment. We suggest deleting this requirement. By definition, consequential load loss following a contingency can not be avoided and should not be considered an impact on the operation of the BES. It should be part of local service reliability between an entity and its local regulatory agency or contractual relationship between individual parties and not in a NERC Standard governing the operation of a BES.

7. Proposed revision to R3.5 – "Manual and automatic generation runback and generator tripping are allowed as a response to single and multiple contingencies as long as Facility Ratings are not exceeded and the result of the generator action, such as loss of reactive resource, impact on reserves, and restart time of tripped unit(s), meets the performance requirements in the tables."

Example for the need for flexibility in the selection of generation runback and/or tripping to meet the requirements of R3.5 – The time period for a particular Emergency Rating might require faster generation redispatch than a runback or set of runbacks are capable of providing. Therefore, it may be necessary to trip one 100 MW unit rather than runback several units for a total of 100 MW. Planning and Operations need flexibility to coordinate with the requirements of Engineering who established the Facility Ratings.

No need for R3.6 with above revision to R3.5.

8. Performance standard "P5" (Q.21- 23) does not allow for the use of load shedding (safety nets) required by some utilities to protect against cascading outages if a transmission line is already out of service and a forced outage of another major element occurs. "System adjustments" might not be possible in a load pocket or local load-serving area to prevent "non-consequential load loss" after loss of a second transmission line to the load-serving area. The use of load shedding for such rare events is an established practice and least cost alternative that does not unreasonably compromise reliability of the WECC system. It is also an acceptable and necessary tradeoff from over burdening customers with additional expensive transmission lines and permitting risk in the West where remote generation resources have historically required power to be carried over long distances.

The tradeoffs between economics (building hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation versus load shedding schemes) and the impact of these rare events should be under the purview of local and state jurisdictions, as long as impacts do not result in cascading events outside of the affected jurisdiction. As long as interconnected reliability or neighboring system operation is not negatively impacted, customer interruption size and frequency should be left to the Transmission Providers discretion and to the jurisdiction of state regulators. The amount of load to be shed and its frequency is primarily an issue for state jurisdiction because it is a matter of the cost/benefit associated with customer service regardless of the voltage level problem. In general, incidences of non-consequential loss of customer load events related to contingencies on the back-bone transmission system are rare when compared to other causes of customer outages. Assuming interruptions to customer service are significant, the state regulators and other related constituents will ultimately be responsible for approving any transmission line facilities or generation additions needed to assure reliability.

Implementing an immediate change to this current established practice is not rational or technically feasible due to the long and arduous regulatory and permitting processes that are required to construct new transmission facilities or new load-side generation. Implementation of the standard as written would take many years. At a minimum, even if it is determined that Congress's intent was to create stricter standards, a phase-in period must be included to allow utilities time to obtain necessary permits, regulatory approval and cost recovery to meet the stricter standards.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

<table>
<tr><th colspan="3">Individual Commenter Information
(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td colspan="3">Name:</td></tr>
<tr><td colspan="3">Organization:</td></tr>
<tr><td colspan="3">Telephone:</td></tr>
<tr><td colspan="3">E-mail:</td></tr>
<tr><td>NERC Region (check all Regions in which your company operates)</td><td></td><td>Registered Ballot Body Segment (check all industry segments in which your company is registered)</td></tr>
<tr><td rowspan="10">☐ ERCOT
☐ FRCC
☐ MRO
☐ NPCC
☐ RFC
☐ SERC
☐ SPP
☐ WECC
☐ NA – Not Applicable</td><td>☐</td><td>1 — Transmission Owners</td></tr>
<tr><td>☐</td><td>2 — RTOs and ISOs</td></tr>
<tr><td>☐</td><td>3 — Load-serving Entities</td></tr>
<tr><td>☐</td><td>4 — Transmission-dependent Utilities</td></tr>
<tr><td>☐</td><td>5 — Electric Generators</td></tr>
<tr><td>☐</td><td>6 — Electricity Brokers, Aggregators, and Marketers</td></tr>
<tr><td>☐</td><td>7 — Large Electricity End Users</td></tr>
<tr><td>☐</td><td>8 — Small Electricity End Users</td></tr>
<tr><td>☐</td><td>9 — Federal, State, Provincial Regulatory or other Government Entities</td></tr>
<tr><td>☐</td><td>10 — Regional Reliability Organizations and Regional Entities</td></tr>
</table>

116-390 Village Boulevard, Princeton, New Jersey 08540-5721
Phone: 609.452.8060 ▪ Fax: 609.452.9550 ▪ www.nerc.com

Group Comments (Complete this page if comments are from a group.)			
Group Name:	**WECC Committees and Subgroups**		
Lead Contact:	**Steve Rueckert**		
Contact Organization:	**WECC**		
Contact Segment:	**10**		
Contact Telephone:	**801 883-6878**		
Contact E-mail:	**steve@wecc.biz**		

Additional Member Name	**Additional Member Organization**	**Region***	**Segment***
Mike Sidiropoulos	PacifiCorp	**WECC**	1
Scott Inglebritson	Seattle City Light	WECC	1,3,4,5
Chad Bowman, PE	Public Utility District #1 of Chelan	WECC	4
Casey Hashimoto	Turlock Irrigation District	WECC	3
Fred Young	Northern California Power Agency	WECC	4
Scott A. Waples	Avista Corporation	WECC	1
Matthew Stoltz	Basin Electric Power Cooperative	WECC	1
Juan C. Sandoval, P.E.	Imperial Irrigation District	WECC	1
Baj Agrawal	Arizona Public Service Co.	WECC	1
Rich Salgo	Sierra Pacific Resources	WECC	1
Brian Whalen	Sierra Pacific Resources	WECC	1
Javier Esparza	Imperial Irrigation District	WECC	1
Milorad Papic	Idaho Power Co.	WECC	1
David Larsen	Transmission Agency of Northern California	WECC	1
Xavier Baldwin	City of Burbank Water & Power	WECC	9
Dana Cabbell	Southern California Edison Co.	WECC	1
Henryk A. Olstowski	Imperial Irrigation District	WECC	5
David Angell	Idaho Power	WECC	1
Charles E. Matthews	Bonneville Power	WECC	1

	Administration		
Mark Graham	Tri-State Generation and Transmission Association	WECC	1

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☒Do not agree.
Q1. **Comment: A Base Case can only represent the amount of transactions required to serve connected load modeled in the case (local load?). A Path Rating case (developed to represent maximum transfers on a path) would not be considered a base case under this definition. WECC develops base cases to study high power transfers under stressed conditions. Such high power transfers necessarily include both firm and non-firm transaction obligations. Therefore, a base case that represents firm transactions to support "connected load" only, cannot be used to support studies of maximum possible power transfer and is of limited value in WECC. We agree that the above definition is one definition of a base case, but we feel that it can not be the only definition or the limiting definition. We suggest that wording be included that reflects the concept of modeling forecasted or above forecasted load levels if desired, and both firm and non-firm transactions if necessary to model anticipated maximum transfers and represent stressed system conditions as well.** **The definition should refer to the base case as a Computer Simulation Model of the power system, not a Computer Representation of the transmission system, since it is used within a computer program and represents load and generation in addition to transmission. References to "the generation dispatch and firm transaction obligations to supply the connected load" should be removed.** **A base case is a starting case for any condition that needs to be studied,**	

not just a firm transactions case. Firm obligations across the transmission system are many times independent of a specific load service obligation.	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☒Do not agree.
Q2. **Comment: Agree with the definition in concept. However, the wording makes the definition seem unrealistic. There are many examples where a certain amount of voltage sensitive load or motor drives sensitive to angle changes are dropped due to normally cleared electrical faults on the transmission system. These loads are not directly connected to the element being removed from service. This type of sympathetic loss of load is unique to the individual customer load. The design of these loads is not under the control of the utilities when it comes to ability to ride through normally cleared faults. We suggest that this definition be modified to include the loss of sensitive load that is not directly connected to the element being removed.** **We propose the following the definition : Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation, and because of sympathetic tripping associated with normal clearing or mis-operation. Load that is lost because it trips due to low voltages experienced during and immediately following the fault (4-6 cycles?) is also considered consequential load loss. We believe this additional recognition is needed because load lost due to low fault voltages is unavoidable and should not result in a standard violation.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☒Do not agree.
Q3. **Comment: Please add the phrase "two or more elements out of service" to the definition from the previous definition in Table I.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: Please add "or Remedial Action schemes" to the end of the definition. FERC Order 693, paragraph 1773 states (6)"clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss." There needs to be a distinction made**	

between Interruptible Load and Firm Demand.	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Agree. ☒Do not agree.
Q7. **Comment: As identified by the modifications above, we believe the definition should be changed to read, "Documented evaluation of future Bulk Electric System needs by the use of performance studies (steady state and dynamic) that cover a range of reasonable or expected assumptions regarding system conditions, applicable time frames, and future plans; including capital reinforcements and operating procedures, SPS/RAS, and other factors (such as asset conditions and age)."**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Plant Stability seems to be a subset of System Stability. Introducing a new term can cause confusion.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the

requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The TP or PA is the most familiar with the system and so would be the best to determine the sensitivities that are more applicable to their particular system. The Standard should not be overly prescriptive. The Standard can make suggestions or list potential sensitivities but let the TP or PA determine those variables to study and the reasonable range of the sensitivities.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: No, as in the response for Question #12. The TP is the best to determine the type of stressing needed for a particular case. This is very evident in the type of cases used for studies in the different parts of the NERC regions.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☒

Comment: We concur with the use of sensitivities as long as the TPs are allowed to determine the sensitivities that are the more appropriate for their systems and not have the sensitivities scripted in the Standard.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: We agree with this conclusion. The Standard language should state that sensitivities are not required in Long-Term Transmission System Planning Horizon but the TP could use sensitivities if desired.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☒

Comment: It is unclear whether “DSM” in this question refers to reduction in load or increases in distributed resources, or if the resources are directly controllable by the transmission operator. DSM could be used in the mix of solutions that are used to determine the optimal solution for a transmission issue. However, we have concerns about the use of DSM, that is not under the direct control of the Transmission Operator as a stand alone transmission system solution. Please remember the overstated returns from DSM in the last decade that did not materialize. If these overstated values had been used as a transmission system enhancement, then the system would have been compromised with emergency operating solution until the effective transmission enhancements could be realized.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒

Comment: No, this is too onerous. We recognize that, when planning the system and developing a Corrective Action Plan, the transmission planner would have added the potential projects individually (or in small groups) into a case to re-test the system performance. Hoever, R2.7.2 seems to require that all potential projects be added back into the case simultaneously for retesting. There could be many different alternative solutions for each potential problem identified in the different study years without having the base solution first determined for a nearer term case. There can be many combinations of potential solutions for cases further into the future that satisfy the condition being studied. For example, a voltage problem can be solved by the addition of capacitors, completing a bus tie, adding a short line, operating procedure, changing generation dispatch, etc. Even assuming that one set of solutions are picked so the verification study can be performed, logistically this demonstration may be too close to the assessment in the following year. Instead of retesting the potential projects in the Corrective Action Plan on the original base case, it may be better to test them in the base cases prepared for following year’s study. Any potential problem that is unresolved will show up again in the following year’s assessment. Therefore, a separate demonstration using an “older” case may not be an efficient use of the TPs' and PAs' time and resources.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒

Comment: The definition of these terms can be vastly different across all TPs. How would this be effectively monitored for compliance with such different definitions? Also, each TO's criteria to go from a proposed project to a committed project can change over time due to other needs and requirements.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒

Comment: The requirement is similar to the question posed in Question 17. What is the documentation that proves this is needed?

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the

		SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the

adjustment followed by loss of a transformer with low side voltage rating above 300 kV		SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒

Comment: We disagree that non-consequential loss of load should not be permitted for this contingency event. We believe that planned and controlled interruption of non-consequential load should be permitted for loss of a non-bus tie breaker (above 300 kV). Losing a non-bus tie breaker could result in simultaneous loss of two or more elements, depending on the bus configuration. Allowing planned and controlled disconnection of some load in the areas would not only prevent cascading and instability (which could result in uncontrolled loss of a larger amount of load), but also enables faster load restoration. Losing a breaker due to an internal fault is a low probability event. To meet this requirement as proposed would require severe pre-contingency curtailment of power transfers, that could impact commerce and/or construction of large number of transmission facilities with the attendant environmental impacts and increased cost to customers.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: We disagree that non-consequential loss of load should not be permitted for this contingency event. We believe that planned and controlled interruption of non-consequential load should be permitted for loss of either a generator, a transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV). This contingency event could result in simultaneous loss of two or more elements, depending on the bus configuration. Allowing planned and controlled disconnection of some load in the areas would not only prevent cascading and instability (which could result in uncontrolled loss of a larger amount of load), but also enables faster load restoration. These contingencies are low-probability events. To meet this requirement as proposed would require severe pre-contingency curtailment of power transfers, that could impact commerce and/or construction of a large number of transmission facilities with the attendant environmental impacts and increased cost to customers.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have

[1] System adjustment can be manual or automatic

		higher probability than other multiple contingency events.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☒

Comment: We agree with the question asked. In addition, transactions that can be interrupted due to the loss of a DC line should not be limited to the firm transactions, that are dependent on the DC line. It should also include interruptible transactions and other transactions made available through negotiated agreements on both AC and DC lines.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an

assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☒

Comment: We agree with the question asked. In addition, because of the time sequence from the start of the fault, through fault clearing and transient dynamic period, the post-transient period to the steady state post-contingency period, there needs to be clear links between the performance requirements in the transient dynamic time period and the steady state time period. For example, if generator dropping or controlled load interruption is allowed in the transient dynamic period, it should also be allowed in the steady state time period that follows. Otherwise, it would put the Transmission Planners and the Planning Authorities in an untenable situation because, once a generator or load is dropped in the first few cycles after the disturbance; it cannot be required to be on line in the minutes that immediately follow.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒

Comment: It appears that Plant Stability Study is a subset of System Stability Study. R4.6.2 states these shall be performed for changes in real power output of a generating unit by more than 10%. Then it states they shall be performed for planning events. R4.5 already covers any contingencies that are an issue and the system already needs to meet some level of performance for loss of the generator. It seems that a change in generation would already be analyzed from a system standpoint as stated in R2.4.3. It appears that material changes to existing generators should be reflected in modeling requirements elsewhere.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment: We agree with the SDT that simultaneous 3-phase fault on all generating units in a plant is improbable and effort should be better spent studying more probable events. In any case, this Extreme Event is to be considered in the Steady State Table, and stability cases can be run if it is shown to be needed in the power flow study results. We are, however, confused by this question. This question states that the SDT did not include the requirement to consider loss of all generators at a plant in the stability, yet the Extreme Event in the stability table shows in No. 9, “3Ø fault with loss of all generating units at a station”.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☒

Comment: The requirement to include motor load should be extended to other load level periods and not be limited to peak load period only. However, to capture slow voltage recover phenomena, especially in areas of high penetration of refrigerated air conditioning load (e.g. 50% to 60%), would require modeling down to the distribution system voltage level and explicitly representing shunt capacitors and various induction motor types (e.g. equivalents for single phase motors). If the requirement is not extended, dynamic simulations will likely differ significantly from observed system events. We recommend a phase-in period so that the requirement for use of load models should only include regionally accepted load models for which data are available. This requirement can be extended or modified as the Region in which the entities reside adopts new load modeling guidelines.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: All adjustments should be allowed as long as they are realistic and achievable in the time frame required and consistent with other study parameters. For example, automatic adjustments would be required for correction of a stability problem, but manual adjustment should be allowed for correction of a thermal problem if there is no instability problem.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Yes. Agree. Conditions for generation run back for N-1: 1) Run back of generation cannot result in tripping of firm load, 2) power flow should be within the time-limited equipment ratings, 3) frequency should be within allowable limits.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Based on the interpretation of the above question, we are providing two responses to this question. The first responds to the limitations placed on RAS, regardless of what action the RAS initiates. The second response specifically addresses RAS that trips generation.

Response 1: RAS should be allowed for single contingency events. Any sort of RAS should be permitted, but there should be a review of the RAS. If the local entities agree to the RAS, it should be allowed. This addresses cost vs. benefit balance. Entities affected should be the ones that determine the best solution for their situation.

Response 2: Generation tripping can be used for single contingency if such application can be demonstrated through transmission planning studies that:

- The generation tripping is planned and controlled ("planned and controlled" means a pre-planned action(s) based on predetermined system conditions that take corrective measure(s) to maintain acceptable system performance).
- The generation tripping does not result in non-consequential load loss.
- System frequency should be within allowable limits.
- System voltage dip and deviation should be within allowable limits.
- The generator owner(s) agrees to the tripping as planned.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: System adjustment involves operator intervention that would be beyond the time frame of RAS operation. Therefore, if a unit is already dropped during RAS or SPS action, it should be assumed to be off-line during system adjustment period.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: Yes. WECC allows tripping of generators to meet single contingency performance requirements. WECC also allows planned and controlled load shedding for the proposed Planning Events P2-1, P2-2, P3, P4 and P5, although we agree with the proposed requirements for P4 due to the higher probability of occurrence. If the standard does not allow for non-consequential load shedding of 300 kV and above for P5 scenarios, WECC will develop a regional variance".

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☒ No ☐

Comment: 1) FERC Order 693, Paragraph 1825 regarding TPL-003, Category C – The Commission directed the ERO to modify footnote (c) to Table 1 to clarify the term "controlled load interruption" rather than eliminate its applicability to this performance requirement. 2) FAC-010-1, R2.3 – "…planned or controlled interruption…" This conflicts with "No" for non-consequential load loss allowed in draft TPL.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment: 1. R1.3 requires the provision of firm transfer/Interchange Schedules and resources required to supply load for each Balancing Authority. It may not be possible to have reasonably accurate information on firm transfers and Interchange Schedules for years into the future. Within WECC, we develop base cases that represent reasonably stressed conditions that model power flows stressing various paths. Therefore, within WECC, we design the system to operate at levels that can support all sorts of commerce, including the effects of loop flow, and firm and non-firm contracts, in addition to other possibilities. It would be difficult to develop information from this mixture that includes only firm transactions for such future base cases. In addition, WECC does not allow operations at levels not previously studied. Therefore, an exercise to determine firm transaction/schedules would produce information that will be of little value to support reliability in WECC.

2. R2.7.1.2 requires identification of system deficiencies and accociated corrective action for the Long Term Transmission Planning Horizon. This requirement needs to tie to the lead times to implement the corrective action(s). For example, if a 500 kV transmission line is needed to correct a deficiency that surfaces in the tenth year, then this requirement is reasonable. However, if the deficiency is on a low voltage system, that can be resolved with short lead-time projects (such as installing a small capacitor bank) then this requirement would seem to be too prescriptive.

3. R1.5 requires providing modeling information as part of R1 on a number of transmission planned facilities, including circuit breakers. Since circuit breakers are part of a transmission line, we are not sure how a circuit breaker would be modeled separately, as required.

4. R3.2.1 requires that "studies shall consider the minimum steady state voltage limitations of all generators". Since generators (as well as other facilities) have both high and low voltage limits, the standard should require consideration of both high and low voltage limits.

5. In R.3.2.2, please provide a reference for relay loadability.

6. R.3.3.2.1. requires that Consequential Load loss (expected maximum demand and expected duration) following a single contingency shall be identified in the Planning Assessment. We suggest deleting this requirement. By definition, consequential load loss following a contingency can not be avoided and should not be considered an impact on the operation of the BES. It should be part of local service reliability between an entity and its local regulatory agency or contractual relationship between individual parties and not in a NERC Standard governing the operation of a BES.

7. Proposed revision to R3.5 – "Manual and automatic generation runback and generator tripping are allowed as a response to single and multiple contingencies as long

as Facility Ratings are not exceeded and the result of the generator action, such as loss of reactive resource, impact on reserves, and restart time of tripped unit(s), meets the performance requirements in the tables."

Example for the need for flexibility in the selection of generation runback and/or tripping to meet the requirements of R3.5 – The time period for a particular Emergency Rating might require faster generation redispatch than a runback or set of runbacks are capable of providing. Therefore, it may be necessary to trip one 100 MW unit rather than runback several units for a total of 100 MW. Planning and Operations need flexibility to coordinate with the requirements of Engineering who established the Facility Ratings.

No need for R3.6 with above revision to R3.5.

8. Performance standard "P5" (Q.21- 23) does not allow for the use of load shedding (safety nets) required by some utilities to protect against cascading outages if a transmission line is already out of service and a forced outage of another major element occurs. "System adjustments" might not be possible in a load pocket or local load-serving area to prevent "non-consequential load loss" after loss of a second transmission line to the load-serving area. The use of load shedding for such rare events is an established practice and least cost alternative that does not unreasonably compromise reliability of the WECC system. It is also an acceptable and necessary tradeoff from over burdening customers with additional expensive transmission lines and permitting risk in the West where remote generation resources have historically required power to be carried over long distances.

The tradeoffs between economics (building hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation versus load shedding schemes) and the impact of these rare events should be under the purview of local and state jurisdictions, as long as impacts do not result in cascading events outside of the affected jurisdiction. As long as interconnected reliability or neighboring system operation is not negatively impacted, customer interruption size and frequency should be left to the Transmission Providers discretion and to the jurisdiction of state regulators. The amount of load to be shed and its frequency is primarily an issue for state jurisdiction because it is a matter of the cost/benefit associated with customer service regardless of the voltage level problem. In general, incidences of non-consequential loss of customer load events related to contingencies on the back-bone transmission system are rare when compared to other causes of customer outages. Assuming interruptions to customer service are significant, the state regulators and other related constituents will ultimately be responsible for approving any transmission line facilities or generation additions needed to assure reliability.

Implementing an immediate change to this current established practice is not rational or technically feasible due to the long and arduous regulatory and permitting processes that are required to construct new transmission facilities or new load-side generation. Implementation of the standard as written would take many years. At a minimum, even if it is determined that Congress's intent was to create stricter standards, a phase-in period must be included to allow utilities time to obtain necessary permits, regulatory approval and cost recovery to meet the stricter standards.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ ERCOT ☐ FRCC ☐ MRO ☐ NPCC ☐ RFC ☐ SERC ☐ SPP ☐ WECC ☐ NA – Not Applicable	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)			
Group Name:	**WECC Committees and Subcommittees**		
Lead Contact:	**Steve Rueckert**		
Contact Organization:	**WECC**		
Contact Segment:	**10**		
Contact Telephone:	**801 883-6878**		
Contact E-mail:	**steve@wecc.biz**		
Additional Member Name	**Additional Member Organization**	**Region***	**Segment***
Spencer Tacke	Modesto Irrigation District	**WECC**	1
Robert Temple	Western Area Power Administration	WECC	9
Greg Lange	Grant County PUD	WECC	3
Dennis Malone	El Paso Electric Company	WECC	1
Garry Chinn	Metropolitan Water District of Southern California	WECC	1,7
Dilip Mahendra	Sacramento Municipal Utility District	WECC	1
Kevin Dasso	Pacific Gas and Electric	WECC	3
Jim Filippi	Pacific Gas and Electric	WECC	1
Laurence Chaset	CPUC	WECC	9
Robert Jenkins	PG&E	WECC	3
Mark Ziering	California Public Utility Commission	WECC	9
Ben Morris	Pacific Gas and Electric	WECC	1
Chifong Thomas	PG&E	WECC	1
Chuck Stigers	Northwestern Energy	WECC	1
James Tucker	Deseret Power	WECC	1
Kristine Buchholz	Pacific Gas and Electric	WECC	1
Robert Mathews	Pacific Gas and Electric	WECC	1
Gary DeShazo	California ISO	WECC	2
Bob Smith	Arizona Public Service	WECC	1

Les Pereira	NCPA	WECC	4

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the

rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☒Do not agree.
Q1. **Comment: A Base Case can only represent the amount of transactions required to serve connected load modeled in the case (local load?). A Path Rating case (developed to represent maximum transfers on a path) would not be considered a base case under this definition. WECC develops base cases to study high power transfers under stressed conditions. Such high power transfers necessarily include both firm and non-firm transaction obligations. Therefore, a base case that represents firm transactions to support "connected load" only, cannot be used to support studies of maximum possible power transfer and is of limited value in WECC. We agree that the above definition is one definition of a base case, but we feel that it can not be the only definition or the limiting definition. We suggest that wording be included that reflects the concept of modeling forecasted or above forecasted load levels if desired, and both firm and non-firm transactions if necessary to model anticipated maximum transfers and represent stressed system conditions as well.** **The definition should refer to the base case as a Computer Simulation Model of the power system, not a Computer Representation of the transmission system, since it is used within a computer program and represents load and generation in addition to transmission. References to "the generation dispatch and firm transaction obligations to supply the connected load" should be removed.** **A base case is a starting case for any condition that needs to be studied, not just a firm transactions case. Firm obligations across the transmission system are many times independent of a specific load service obligation.**	
Q2. **Consequential Load Loss:** Load that is no longer served	☒Agree.

because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Do not agree.
Q2. **Comment: Agree with the definition in concept. However, the wording makes the definition seem unrealistic. There are many examples where a certain amount of voltage sensitive load or motor drives sensitive to angle changes are dropped due to normally cleared electrical faults on the transmission system. These loads are not directly connected to the element being removed from service. This type of sympathetic loss of load is unique to the individual customer load. The design of these loads is not under the control of the utilities when it comes to ability to ride through normally cleared faults. We suggest that this definition be modified to include the loss of sensitive load that is not directly connected to the element being removed.** **We propose the following the definition : Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation, and because of sympathetic tripping associated with normal clearing or mis-operation. Load that is lost because it trips due to low voltages experienced during and immediately following the fault (4-6 cycles?) is also considered consequential load loss. We believe this additional recognition is needed because load lost due to low fault voltages is unavoidable and should not result in a standard violation.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☒Do not agree.
Q3. **Comment: Please add the phrase "two or more elements out of service" to the definition from the previous definition in Table I.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: Please add "or Remedial Action schemes" to the end of the definition. FERC Order 693, paragraph 1773 states (6)"clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss." There needs to be a distinction made between Interruptible Load and Firm Demand.**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that	☒Agree.

cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Do not agree.
Q7. **Comment: As identified by the modifications above, we believe the definition should be changed to read, "Documented evaluation of future Bulk Electric System needs by the use of performance studies (steady state and dynamic) that cover a range of reasonable or expected assumptions regarding system conditions, applicable time frames, and future plans; including capital reinforcements and operating procedures, SPS/RAS, and other factors (such as asset conditions and age)."**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Plant Stability seems to be a subset of System Stability. Introducing a new term can cause confusion.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the

rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The TP or PA is the most familiar with the system and so would be the best to determine the sensitivities that are more applicable to their particular system. The Standard should not be overly prescriptive. The Standard can make suggestions or list potential sensitivities but let the TP or PA determine those variables to study and the reasonable range of the sensitivities.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: No, as in the response for Question #12. The TP is the best to determine the type of stressing needed for a particular case. This is very evident in the type of cases used for studies in the different parts of the NERC regions.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☒

Comment: We concur with the use of sensitivities as long as the TPs are allowed to determine the sensitivities that are the more appropriate for their systems and not have the sensitivities scripted in the Standard.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: We agree with this conclusion. The Standard language should state that sensitivities are not required in Long-Term Transmission System Planning Horizon but the TP could use sensitivities if desired.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes

all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☒

Comment: It is unclear whether "DSM" in this question refers to reduction in load or increases in distributed resources, or if the resources are directly controllable by the transmission operator. DSM could be used in the mix of solutions that are used to determine the optimal solution for a transmission issue. However, we have concerns about the use of DSM, that is not under the direct control of the Transmission Operator as a stand alone transmission system solution. Please remember the overstated returns from DSM in the last decade that did not materialize. If these overstated values had been used as a transmission system enhancement, then the system would have been compromised with emergency operating solution until the effective transmission enhancements could be realized.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒

Comment: No, this is too onerous. We recognize that, when planning the system and developing a Corrective Action Plan, the transmission planner would have added the potential projects individually (or in small groups) into a case to re-test the system performance. Hoever, R2.7.2 seems to require that all potential projects be added back into the case simultaneously for retesting. There could be many different alternative solutions for each potential problem identified in the different study years without having the base solution first determined for a nearer term case. There can be many combinations of potential solutions for cases further into the future that satisfy the condition being studied. For example, a voltage problem can be solved by the addition of capacitors, completing a bus tie, adding a short line, operating procedure, changing generation dispatch, etc. Even assuming that one set of solutions are picked so the verification study can be performed, logistically this demonstration may be too close to the assessment in the following year. Instead of retesting the potential projects in the Corrective Action Plan on the original base case, it may be better to test them in the base cases prepared for following year's study. Any potential problem that is unresolved will show up again in the following year's assessment. Therefore, a separate demonstration using an "older" case may not be an efficient use of the TPs' and PAs' time and resources.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒
Comment: The definition of these terms can be vastly different across all TPs. How would this be effectively monitored for compliance with such different definitions? Also, each TO's criteria to go from a proposed project to a committed project can change over time due to other needs and requirements.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒
Comment: The requirement is similar to the question posed in Question 17. What is the documentation that proves this is needed?

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as

		proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as

		proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒

Comment: We disagree that non-consequential loss of load should not be permitted for this contingency event. We believe that planned and controlled interruption of non-consequential load should be permitted for loss of a non-bus tie breaker (above 300 kV). Losing a non-bus tie breaker could result in simultaneous loss of two or more elements, depending on the bus configuration. Allowing planned and controlled disconnection of some load in the areas would not only prevent cascading and instability (which could result in uncontrolled loss of a larger amount of load), but also enables faster load restoration. Losing a breaker due to an internal fault is a low probability event. To meet this requirement as proposed would require severe pre-contingency curtailment of power transfers, that could impact commerce and/or construction of large number of transmission facilities with the attendant environmental impacts and increased cost to customers.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: We disagree that non-consequential loss of load should not be permitted for this contingency event. We believe that planned and controlled interruption of non-consequential load should be permitted for loss of either a generator, a transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV). This contingency event could result in simultaneous loss of two or more elements, depending on the bus configuration. Allowing planned and controlled disconnection of some load in the areas would not only prevent cascading and instability (which could result in uncontrolled loss of a larger amount of load), but also enables faster load restoration. These contingencies are low-probability events. To meet this requirement as proposed would require severe pre-contingency curtailment of power transfers, that could impact commerce and/or construction of a large number of transmission facilities with the attendant environmental impacts and increased cost to customers.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Q27. P4-2: Loss of a generator followed by a System adjustment followed	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability

[1] System adjustment can be manual or automatic

by the loss of a monopolar DC line		and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☒

Comment: We agree with the question asked. In addition, transactions that can be interrupted due to the loss of a DC line should not be limited to the firm transactions, that are dependent on the DC line. It should also include interruptible transactions and other transactions made available through negotiated agreements on both AC and DC lines.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☒

Comment: We agree with the question asked. In addition, because of the time sequence from the start of the fault, through fault clearing and transient dynamic period, the post-transient period to the steady state post-contingency period, there needs to be clear links between the performance requirements in the transient dynamic time period and the steady state time period. For example, if generator dropping or controlled load interruption is allowed in the transient dynamic period, it should also be allowed in the steady state time period that follows. Otherwise, it would put the Transmission Planners and the Planning Authorities in an untenable situation because, once a generator or load is dropped in the first few cycles after the disturbance; it cannot be required to be on line in the minutes that immediately follow.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒

Comment: It appears that Plant Stability Study is a subset of System Stability Study. R4.6.2 states these shall be performed for changes in real power output of a generating unit by more than 10%. Then it states they shall be performed for planning events. R4.5 already covers any contingencies that are an issue and the system already needs to meet some level of performance for loss of the generator. It seems that a change in generation would already be analyzed from a system standpoint as stated in R2.4.3. It appears that material changes to existing generators should be reflected in modeling requirements elsewhere.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment: We agree with the SDT that simultaneous 3-phase fault on all generating units in a plant is improbable and effort should be better spent studying more probable events. In any case, this Extreme Event is to be considered in the Steady State Table, and stability cases can be run if it is shown to be needed in the power flow study results. We are, however, confused by this question. This question states that the SDT did not include the requirement to consider loss of all generators at a plant in the stability, yet the Extreme Event in the stability table shows in No. 9, “3Ø fault with loss of all generating units at a station”.

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☒

Comment: The requirement to include motor load should be extended to other load level periods and not be limited to peak load period only. However, to capture slow voltage recover phenomena, especially in areas of high penetration of refrigerated air conditioning load (e.g. 50% to 60%), would require modeling down to the distribution system voltage level and explicitly representing shunt capacitors and various induction motor types (e.g. equivalents for single phase motors). If the requirement is not extended, dynamic simulations will likely differ significantly from observed system events. We recommend a phase-in period so that the requirement for use of load models should only include regionally accepted load models for which data are available. This requirement can be extended or modified as the Region in which the entities reside adopts new load modeling guidelines.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: All adjustments should be allowed as long as they are realistic and achievable in the time frame required and consistent with other study parameters. For example, automatic adjustments would be required for correction of a stability problem, but manual adjustment should be allowed for correction of a thermal problem if there is no instability problem.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Yes. Agree. Conditions for generation run back for N-1: 1) Run back of generation cannot result in tripping of firm load, 2) power flow should be within the time-limited equipment ratings, 3) frequency should be within allowable limits.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Based on the interpretation of the above question, we are providing two responses to this question. The first responds to the limitations placed on RAS, regardless of what action the RAS initiates. The second response specifically addresses RAS that trips generation.

Response 1: RAS should be allowed for single contingency events. Any sort of RAS should be permitted, but there should be a review of the RAS. If the local entities agree to the RAS, it should be allowed. This addresses cost vs. benefit balance. Entities affected should be the ones that determine the best solution for their situation.

Response 2: Generation tripping can be used for single contingency if such application can be demonstrated through transmission planning studies that:

- The generation tripping is planned and controlled ("planned and controlled" means a pre-planned action(s) based on predetermined system conditions that take corrective measure(s) to maintain acceptable system performance).
- The generation tripping does not result in non-consequential load loss.
- System frequency should be within allowable limits.
- System voltage dip and deviation should be within allowable limits.
- The generator owner(s) agrees to the tripping as planned.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: System adjustment involves operator intervention that would be beyond the time frame of RAS operation. Therefore, if a unit is already dropped during RAS or SPS action, it should be assumed to be off-line during system adjustment period.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: Yes. WECC allows tripping of generators to meet single contingency performance requirements. WECC also allows planned and controlled load shedding for the proposed Planning Events P2-1, P2-2, P3, P4 and P5, although we agree with the proposed requirements for P4 due to the higher probability of occurrence. If the standard does not allow for non-consequential load shedding of 300 kV and above for P5 scenarios, WECC will develop a regional variance".

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☒ No ☐
Comment: 1) FERC Order 693, Paragraph 1825 regarding TPL-003, Category C – The Commission directed the ERO to modify footnote (c) to Table 1 to clarify the term "controlled load interruption" rather than

eliminate its applicability to this performance requirement. 2) FAC-010-1, R2.3 – "…planned or controlled interruption…" This conflicts with "No" for non-consequential load loss allowed in draft TPL.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment: 1. R1.3 requires the provision of firm transfer/Interchange Schedules and resources required to supply load for each Balancing Authority. It may not be possible to have reasonably accurate information on firm transfers and Interchange Schedules for years into the future. Within WECC, we develop base cases that represent reasonably stressed conditions that model power flows stressing various paths. Therefore, within WECC, we design the system to operate at levels that can support all sorts of commerce, including the effects of loop flow, and firm and non-firm contracts, in addition to other possibilities. It would be difficult to develop information from this mixture that includes only firm transactions for such future base cases. In addition, WECC does not allow operations at levels not previously studied. Therefore, an exercise to determine firm transaction/schedules would produce information that will be of little value to support reliability in WECC.

2. R2.7.1.2 requires identification of system deficiencies and accociated corrective action for the Long Term Transmission Planning Horizon. This requirement needs to tie to the lead times to implement the corrective action(s). For example, if a 500 kV transmission line is needed to correct a deficiency that surfaces in the tenth year, then this requirement is reasonable. However, if the deficiency is on a low voltage system, that can be resolved with short lead-time projects (such as installing a small capacitor bank) then this requirement would seem to be too prescriptive.

3. R1.5 requires providing modeling information as part of R1 on a number of transmission planned facilities, including circuit breakers. Since circuit breakers are part of a transmission line, we are not sure how a circuit breaker would be modeled separately, as required.

4. R3.2.1 requires that "studies shall consider the minimum steady state voltage limitations of all generators". Since generators (as well as other facilities) have both high and low voltage limits, the standard should require consideration of both high and low voltage limits.

5. In R.3.2.2, please provide a reference for relay loadability.

6. R.3.3.2.1. requires that Consequential Load loss (expected maximum demand and expected duration) following a single contingency shall be identified in the Planning Assessment. We suggest deleting this requirement. By definition, consequential load loss following a contingency can not be avoided and should not be considered an impact on the operation of the BES. It should be part of local service reliability between an entity and its local regulatory agency or contractual relationship between individual parties and not in a NERC Standard governing the operation of a BES.

7. Proposed revision to R3.5 – "Manual and automatic generation runback and generator tripping are allowed as a response to single and multiple contingencies as long as Facility Ratings are not exceeded and the result of the generator action, such as loss of reactive resource, impact on reserves, and restart time of tripped unit(s), meets the performance requirements in the tables."

Example for the need for flexibility in the selection of generation runback and/or tripping to meet the requirements of R3.5 – The time period for a particular Emergency Rating might require faster generation redispatch than a runback or set of runbacks are capable of providing. Therefore, it may be necessary to trip one 100 MW unit rather than runback several units for a total of 100 MW. Planning and Operations need flexibility to coordinate with the requirements of Engineering who established the Facility Ratings.

No need for R3.6 with above revision to R3.5.

8. Performance standard "P5" (Q.21- 23) does not allow for the use of load shedding (safety nets) required by some utilities to protect against cascading outages if a transmission line is already out of service and a forced outage of another major element occurs. "System adjustments" might not be possible in a load pocket or local load-serving area to prevent "non-consequential load loss" after loss of a second transmission line to the load-serving area. The use of load shedding for such rare events is an established practice and least cost alternative that does not unreasonably compromise reliability of the WECC system. It is also an acceptable and necessary tradeoff from over burdening customers with additional expensive transmission lines and permitting risk in the West where remote generation resources have historically required power to be carried over long distances.

The tradeoffs between economics (building hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation versus load shedding schemes) and the impact of these rare events should be under the purview of local and state jurisdictions, as long as impacts do not result in cascading events outside of the affected jurisdiction. As long as interconnected reliability or neighboring system operation is not negatively impacted, customer interruption size and frequency should be left to the Transmission Providers discretion and to the jurisdiction of state regulators. The amount of load to be shed and its frequency is primarily an issue for state jurisdiction because it is a matter of the cost/benefit associated with customer service regardless of the voltage level problem. In general, incidences of non-consequential loss of customer load events related to contingencies on the back-bone transmission system are rare when compared to other causes of customer outages. Assuming interruptions to customer service are significant, the state regulators and other related constituents will ultimately be responsible for approving any transmission line facilities or generation additions needed to assure reliability.

Implementing an immediate change to this current established practice is not rational or technically feasible due to the long and arduous regulatory and permitting processes that are required to construct new transmission facilities or new load-side generation. Implementation of the standard as written would take many years. At a minimum, even if it is determined that Congress's intent was to create stricter standards, a phase-in period must be included to allow utilities time to obtain necessary permits, regulatory approval and cost recovery to meet the stricter standards.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: **WECC Committees and Subgroups**

Lead Contact: **Steve Rueckert**

Contact Organization: **WECC**

Contact Segment: **10**

Contact Telephone: **801 883-6878**

Contact E-mail: **steve@wecc.biz**

Additional Member Name	Additional Member Organization	Region*	Segment*
Jay Seitz	USBR	**WECC**	4
Kevin Conway	GCPD	WECC	4
Alan Roth	Calpine	WECC	5
Thomas Green	Public Service Co. of Colorado (XCEL)	WECC	1
Brian Keel	Salt River Project	WECC	1
Bill Hosie	TransCanada Energy	WECC	4
Robert Kondziolka	SRP	WECC	1
Tom Duane	Public Service Company of New Mexico	WECC	1,3
Dan Lyons	Aquila	WECC	1
John Collins	Platte River Power	WECC	1

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the

rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☒Do not agree.
Q1. **Comment: A Base Case can only represent the amount of transactions required to serve connected load modeled in the case (local load?). A Path Rating case (developed to represent maximum transfers on a path) would not be considered a base case under this definition. WECC develops base cases to study high power transfers under stressed conditions. Such high power transfers necessarily include both firm and non-firm transaction obligations. Therefore, a base case that represents firm transactions to support "connected load" only, cannot be used to support studies of maximum possible power transfer and is of limited value in WECC. We agree that the above definition is one definition of a base case, but we feel that it can not be the only definition or the limiting definition. We suggest that wording be included that reflects the concept of modeling forecasted or above forecasted load levels if desired, and both firm and non-firm transactions if necessary to model anticipated maximum transfers and represent stressed system conditions as well.** **The definition should refer to the base case as a Computer Simulation Model of the power system, not a Computer Representation of the transmission system, since it is used within a computer program and represents load and generation in addition to transmission. References to "the generation dispatch and firm transaction obligations to supply the connected load" should be removed.** **A base case is a starting case for any condition that needs to be studied, not just a firm transactions case. Firm obligations across the transmission system are many times independent of a specific load service obligation.**	
Q2. **Consequential Load Loss:** Load that is no longer served	☒Agree.

because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Do not agree.
Q2. **Comment: Agree with the definition in concept. However, the wording makes the definition seem unrealistic. There are many examples where a certain amount of voltage sensitive load or motor drives sensitive to angle changes are dropped due to normally cleared electrical faults on the transmission system. These loads are not directly connected to the element being removed from service. This type of sympathetic loss of load is unique to the individual customer load. The design of these loads is not under the control of the utilities when it comes to ability to ride through normally cleared faults. We suggest that this definition be modified to include the loss of sensitive load that is not directly connected to the element being removed.** **We propose the following the definition : Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation, and because of sympathetic tripping associated with normal clearing or mis-operation. Load that is lost because it trips due to low voltages experienced during and immediately following the fault (4-6 cycles?) is also considered consequential load loss. We believe this additional recognition is needed because load lost due to low fault voltages is unavoidable and should not result in a standard violation.**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☒Agree. ☒Do not agree.
Q3. **Comment: Please add the phrase "two or more elements out of service" to the definition from the previous definition in Table I.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☒Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☒Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☐Agree. ☒Do not agree.
Q6. **Comment: Please add "or Remedial Action schemes" to the end of the definition. FERC Order 693, paragraph 1773 states (6)"clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss." There needs to be a distinction made between Interruptible Load and Firm Demand.**	
Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that	☒Agree.

cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☒Do not agree.
Q7. **Comment: As identified by the modifications above, we believe the definition should be changed to read, "Documented evaluation of future Bulk Electric System needs by the use of performance studies (steady state and dynamic) that cover a range of reasonable or expected assumptions regarding system conditions, applicable time frames, and future plans; including capital reinforcements and operating procedures, SPS/RAS, and other factors (such as asset conditions and age)."**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☒Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: Plant Stability seems to be a subset of System Stability. Introducing a new term can cause confusion.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☒Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☒Agree. ☐Do not agree.
Q11. **Comment:**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the

rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☒

Comment: The TP or PA is the most familiar with the system and so would be the best to determine the sensitivities that are more applicable to their particular system. The Standard should not be overly prescriptive. The Standard can make suggestions or list potential sensitivities but let the TP or PA determine those variables to study and the reasonable range of the sensitivities.

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Yes ☐ No ☒

Comment: No, as in the response for Question #12. The TP is the best to determine the type of stressing needed for a particular case. This is very evident in the type of cases used for studies in the different parts of the NERC regions.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☒

Comment: We concur with the use of sensitivities as long as the TPs are allowed to determine the sensitivities that are the more appropriate for their systems and not have the sensitivities scripted in the Standard.

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐

Comment: We agree with this conclusion. The Standard language should state that sensitivities are not required in Long-Term Transmission System Planning Horizon but the TP could use sensitivities if desired.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes

all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☒

Comment: It is unclear whether “DSM” in this question refers to reduction in load or increases in distributed resources, or if the resources are directly controllable by the transmission operator. DSM could be used in the mix of solutions that are used to determine the optimal solution for a transmission issue. However, we have concerns about the use of DSM, that is not under the direct control of the Transmission Operator as a stand alone transmission system solution. Please remember the overstated returns from DSM in the last decade that did not materialize. If these overstated values had been used as a transmission system enhancement, then the system would have been compromised with emergency operating solution until the effective transmission enhancements could be realized.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☐ No ☒

Comment: No, this is too onerous. We recognize that, when planning the system and developing a Corrective Action Plan, the transmission planner would have added the potential projects individually (or in small groups) into a case to re-test the system performance. Hoever, R2.7.2 seems to require that all potential projects be added back into the case simultaneously for retesting. There could be many different alternative solutions for each potential problem identified in the different study years without having the base solution first determined for a nearer term case. There can be many combinations of potential solutions for cases further into the future that satisfy the condition being studied. For example, a voltage problem can be solved by the addition of capacitors, completing a bus tie, adding a short line, operating procedure, changing generation dispatch, etc. Even assuming that one set of solutions are picked so the verification study can be performed, logistically this demonstration may be too close to the assessment in the following year. Instead of retesting the potential projects in the Corrective Action Plan on the original base case, it may be better to test them in the base cases prepared for following year’s study. Any potential problem that is unresolved will show up again in the following year’s assessment. Therefore, a separate demonstration using an “older” case may not be an efficient use of the TPs' and PAs' time and resources.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☐ No ☒

Comment: The definition of these terms can be vastly different across all TPs. How would this be effectively monitored for compliance with such different definitions? Also, each TO's criteria to go from a proposed project to a committed project can change over time due to other needs and requirements.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☐ No ☒

Comment: The requirement is similar to the question posed in Question 17. What is the documentation that proves this is needed?

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as

		proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as

		proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☒

Comment: We disagree that non-consequential loss of load should not be permitted for this contingency event. We believe that planned and controlled interruption of non-consequential load should be permitted for loss of a non-bus tie breaker (above 300 kV). Losing a non-bus tie breaker could result in simultaneous loss of two or more elements, depending on the bus configuration. Allowing planned and controlled disconnection of some load in the areas would not only prevent cascading and instability (which could result in uncontrolled loss of a larger amount of load), but also enables faster load restoration. Losing a breaker due to an internal fault is a low probability event. To meet this requirement as proposed would require severe pre-contingency curtailment of power transfers, that could impact commerce and/or construction of large number of transmission facilities with the attendant environmental impacts and increased cost to customers.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☒

Comment: We disagree that non-consequential loss of load should not be permitted for this contingency event. We believe that planned and controlled interruption of non-consequential load should be permitted for loss of either a generator, a transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV). This contingency event could result in simultaneous loss of two or more elements, depending on the bus configuration. Allowing planned and controlled disconnection of some load in the areas would not only prevent cascading and instability (which could result in uncontrolled loss of a larger amount of load), but also enables faster load restoration. These contingencies are low-probability events. To meet this requirement as proposed would require severe pre-contingency curtailment of power transfers, that could impact commerce and/or construction of a large number of transmission facilities with the attendant environmental impacts and increased cost to customers.

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Q27. P4-2: Loss of a generator followed by a System adjustment followed	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability

[1] System adjustment can be manual or automatic

by the loss of a monopolar DC line		and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☒

Comment: We agree with the question asked. In addition, transactions that can be interrupted due to the loss of a DC line should not be limited to the firm transactions, that are dependent on the DC line. It should also include interruptible transactions and other transactions made available through negotiated agreements on both AC and DC lines.

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☒

Comment: We agree with the question asked. In addition, because of the time sequence from the start of the fault, through fault clearing and transient dynamic period, the post-transient period to the steady state post-contingency period, there needs to be clear links between the performance requirements in the transient dynamic time period and the steady state time period. For example, if generator dropping or controlled load interruption is allowed in the transient dynamic period, it should also be allowed in the steady state time period that follows. Otherwise, it would put the Transmission Planners and the Planning Authorities in an untenable situation because, once a generator or load is dropped in the first few cycles after the disturbance; it cannot be required to be on line in the minutes that immediately follow.

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☐ No ☒

Comment: It appears that Plant Stability Study is a subset of System Stability Study. R4.6.2 states these shall be performed for changes in real power output of a generating unit by more than 10%. Then it states they shall be performed for planning events. R4.5 already covers any contingencies that are an issue and the system already needs to meet some level of performance for loss of the generator. It seems that a change in generation would already be analyzed from a system standpoint as stated in R2.4.3. It appears that material changes to existing generators should be reflected in modeling requirements elsewhere.

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☐ No ☒

Comment: We agree with the SDT that simultaneous 3-phase fault on all generating units in a plant is improbable and effort should be better spent studying more probable events. In any case, this Extreme Event is to be considered in the Steady State Table, and stability cases can be run if it is shown to be needed in the power flow study results. We are, however, confused by this question. This question states that the SDT did not include the requirement to consider loss of all generators at a plant in the stability, yet the Extreme Event in the stability table shows in No. 9, "3Ø fault with loss of all generating units at a station".

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☒

Comment: The requirement to include motor load should be extended to other load level periods and not be limited to peak load period only. However, to capture slow voltage recover phenomena, especially in areas of high penetration of refrigerated air conditioning load (e.g. 50% to 60%), would require modeling down to the distribution system voltage level and explicitly representing shunt capacitors and various induction motor types (e.g. equivalents for single phase motors). If the requirement is not extended, dynamic simulations will likely differ significantly from observed system events. We recommend a phase-in period so that the requirement for use of load models should only include regionally accepted load models for which data are available. This requirement can be extended or modified as the Region in which the entities reside adopts new load modeling guidelines.

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment: All adjustments should be allowed as long as they are realistic and achievable in the time frame required and consistent with other study parameters. For example, automatic adjustments would be required for correction of a stability problem, but manual adjustment should be allowed for correction of a thermal problem if there is no instability problem.

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: Yes. Agree. Conditions for generation run back for N-1: 1) Run back of generation cannot result in tripping of firm load, 2) power flow should be within the time-limited equipment ratings, 3) frequency should be within allowable limits.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment:

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: Based on the interpretation of the above question, we are providing two responses to this question. The first responds to the limitations placed on RAS, regardless of what action the RAS initiates. The second response specifically addresses RAS that trips generation.

Response 1: RAS should be allowed for single contingency events. Any sort of RAS should be permitted, but there should be a review of the RAS. If the local entities agree to the RAS, it should be allowed. This addresses cost vs. benefit balance. Entities affected should be the ones that determine the best solution for their situation.

Response 2: Generation tripping can be used for single contingency if such application can be demonstrated through transmission planning studies that:

- The generation tripping is planned and controlled ("planned and controlled" means a pre-planned action(s) based on predetermined system conditions that take corrective measure(s) to maintain acceptable system performance).
- The generation tripping does not result in non-consequential load loss.
- System frequency should be within allowable limits.
- System voltage dip and deviation should be within allowable limits.
- The generator owner(s) agrees to the tripping as planned.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: System adjustment involves operator intervention that would be beyond the time frame of RAS operation. Therefore, if a unit is already dropped during RAS or SPS action, it should be assumed to be off-line during system adjustment period.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☒ No ☐
Comment: Yes. WECC allows tripping of generators to meet single contingency performance requirements. WECC also allows planned and controlled load shedding for the proposed Planning Events P2-1, P2-2, P3, P4 and P5, although we agree with the proposed requirements for P4 due to the higher probability of occurrence. If the standard does not allow for non-consequential load shedding of 300 kV and above for P5 scenarios, WECC will develop a regional variance".

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☒ No ☐
Comment: 1) FERC Order 693, Paragraph 1825 regarding TPL-003, Category C – The Commission directed the ERO to modify footnote (c) to Table 1 to clarify the term "controlled load interruption" rather than

eliminate its applicability to this performance requirement. 2) FAC-010-1, R2.3 – "…planned or controlled interruption…" This conflicts with "No" for non-consequential load loss allowed in draft TPL.

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐

Comment: 1. R1.3 requires the provision of firm transfer/Interchange Schedules and resources required to supply load for each Balancing Authority. It may not be possible to have reasonably accurate information on firm transfers and Interchange Schedules for years into the future. Within WECC, we develop base cases that represent reasonably stressed conditions that model power flows stressing various paths. Therefore, within WECC, we design the system to operate at levels that can support all sorts of commerce, including the effects of loop flow, and firm and non-firm contracts, in addition to other possibilities. It would be difficult to develop information from this mixture that includes only firm transactions for such future base cases. In addition, WECC does not allow operations at levels not previously studied. Therefore, an exercise to determine firm transaction/schedules would produce information that will be of little value to support reliability in WECC.

2. R2.7.1.2 requires identification of system deficiencies and accociated corrective action for the Long Term Transmission Planning Horizon. This requirement needs to tie to the lead times to implement the corrective action(s). For example, if a 500 kV transmission line is needed to correct a deficiency that surfaces in the tenth year, then this requirement is reasonable. However, if the deficiency is on a low voltage system, that can be resolved with short lead-time projects (such as installing a small capacitor bank) then this requirement would seem to be too prescriptive.

3. R1.5 requires providing modeling information as part of R1 on a number of transmission planned facilities, including circuit breakers. Since circuit breakers are part of a transmission line, we are not sure how a circuit breaker would be modeled separately, as required.

4. R3.2.1 requires that "studies shall consider the minimum steady state voltage limitations of all generators". Since generators (as well as other facilities) have both high and low voltage limits, the standard should require consideration of both high and low voltage limits.

5. In R.3.2.2, please provide a reference for relay loadability.

6. R.3.3.2.1. requires that Consequential Load loss (expected maximum demand and expected duration) following a single contingency shall be identified in the Planning Assessment. We suggest deleting this requirement. By definition, consequential load loss following a contingency can not be avoided and should not be considered an impact on the operation of the BES. It should be part of local service reliability between an entity and its local regulatory agency or contractual relationship between individual parties and not in a NERC Standard governing the operation of a BES.

7. Proposed revision to R3.5 – "Manual and automatic generation runback and generator tripping are allowed as a response to single and multiple contingencies as long as Facility Ratings are not exceeded and the result of the generator action, such as loss of reactive resource, impact on reserves, and restart time of tripped unit(s), meets the performance requirements in the tables."

Example for the need for flexibility in the selection of generation runback and/or tripping to meet the requirements of R3.5 – The time period for a particular Emergency Rating might require faster generation redispatch than a runback or set of runbacks are capable of providing. Therefore, it may be necessary to trip one 100 MW unit rather than runback several units for a total of 100 MW. Planning and Operations need flexibility to coordinate with the requirements of Engineering who established the Facility Ratings.

No need for R3.6 with above revision to R3.5.

8. Performance standard "P5" (Q.21- 23) does not allow for the use of load shedding (safety nets) required by some utilities to protect against cascading outages if a transmission line is already out of service and a forced outage of another major element occurs. "System adjustments" might not be possible in a load pocket or local load-serving area to prevent "non-consequential load loss" after loss of a second transmission line to the load-serving area. The use of load shedding for such rare events is an established practice and least cost alternative that does not unreasonably compromise reliability of the WECC system. It is also an acceptable and necessary tradeoff from over burdening customers with additional expensive transmission lines and permitting risk in the West where remote generation resources have historically required power to be carried over long distances.

The tradeoffs between economics (building hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation versus load shedding schemes) and the impact of these rare events should be under the purview of local and state jurisdictions, as long as impacts do not result in cascading events outside of the affected jurisdiction. As long as interconnected reliability or neighboring system operation is not negatively impacted, customer interruption size and frequency should be left to the Transmission Providers discretion and to the jurisdiction of state regulators. The amount of load to be shed and its frequency is primarily an issue for state jurisdiction because it is a matter of the cost/benefit associated with customer service regardless of the voltage level problem. In general, incidences of non-consequential loss of customer load events related to contingencies on the back-bone transmission system are rare when compared to other causes of customer outages. Assuming interruptions to customer service are significant, the state regulators and other related constituents will ultimately be responsible for approving any transmission line facilities or generation additions needed to assure reliability.

Implementing an immediate change to this current established practice is not rational or technically feasible due to the long and arduous regulatory and permitting processes that are required to construct new transmission facilities or new load-side generation. Implementation of the standard as written would take many years. At a minimum, even if it is determined that Congress's intent was to create stricter standards, a phase-in period must be included to allow utilities time to obtain necessary permits, regulatory approval and cost recovery to meet the stricter standards.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for First Draft of TPL-001-1 — Transmission System Planning Performance Requirements

Please use this form to submit comments on the proposed draft of TPL-001-1. Comments must be submitted by **Friday, October 26, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "TPL-001 Draft 1" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolksi@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Christopher Plante	
Organization:	Wisconsin Public Service Corp	
Telephone:	920-433-1290	
E-mail:	ctplante@wisconsinpublicservice.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ ERCOT	☐	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs and ISOs
☒ MRO	☒	3 — Load-serving Entities
☐ NPCC	☒	4 — Transmission-dependent Utilities
☐ RFC	☒	5 — Electric Generators
☐ SERC	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ SPP	☐	7 — Large Electricity End Users
☐ WECC	☐	8 — Small Electricity End Users
☐ NA – Not Applicable	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background

The purpose of this standard is to establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This standard will replace TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team has not yet addressed TPL-005-0 and TPL-006-0, but will address these two standards during the next phase of the drafting process.

The major objectives of the standard drafting team are to:

1) Ensure the standard is complete and the requirements are set at an appropriate level to ensure reliability (Not Least Common Denominator)
2) Ensure that the standard is enforceable by having clearly defined requirements with unambiguous language
3) Address the issues raised by FERC Order 693, 890, and other applicable orders
4) Address the issues raised in the original Standards Authorization Request (SAR) and the Supplemental SAR.

The standard drafting team did not attempt to edit the existing standards but rather chose to write one standard that addresses all aspects of transmission planning in the existing TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The standard drafting team organized the new standard in the following sections:

R1 – Modeling requirements
R2 – Assessment and Corrective Plan requirements
R3 – Steady State Analysis requirements
R4 – Stability Analysis requirements
R5 – Coordination requirements

The standard drafting team determined that the requirements and analysis for Steady State are different from those for stability. As such, the standard drafting team separated the analysis requirements and created two performance requirement tables.

The standard drafting team recognizes that this draft standard is a starting point for industry input into the standard and that there is still a lot of work required to complete the process. The standard drafting team has made many changes to clarify requirements, add requirements, and make some of the performance requirements stricter. The standard drafting team has not addressed Measures, Risk Factors, Violation Severity Factors, or Time Horizons at this time. These will be addressed when the standard drafting team has better defined the requirements of the standard.

For questions where you agree with the standard drafting team, please state that you agree and if available, please provide supporting documentation. If you disagree with the standard drafting team, please explain why you disagree and provide data to support your position, such as outage data or analysis. If you believe that we have made a performance requirement too strict please provide supporting documentation. If applicable, please include the approximate cost in man-hours for additional studies and/or cost in $Millions for additional transmission investment to meet the new requirements or the stricter requirements. If you believe that the standard should be stricter, please provide the rationale along with any supporting data, including existing practices, cost estimates or additional analysis.

To improve the standard, the standard drafting team would appreciate responses to as many of these questions as you can answer.

A. New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

Definition	**Agree or Disagree**
Q1. **Base Case**: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.	☒Agree. ☐Do not agree.
Q1. **Comment:**	
Q2. **Consequential Load Loss:** Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.	☒Agree. ☐Do not agree.
Q2. **Comment:**	
Q3. **Extreme Events:** Events which are more severe than Planning Events and have a low probability of occurrence.	☐Agree. ☒Do not agree.
Q3. **Comment: By definition, Extreme Events are not Planning Events. However, only the definition Planning Events has a requirement to meeting performance requirements. I believe Extreme Events also have performance requirements under R3.4 and its definition should reflect this.**	
Q4. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond.	☐Agree. ☐Do not agree.
Q4. **Comment:**	
Q5. **Near-Term Transmission Planning Horizon:** Transmission planning period that covers years One through five.	☐Agree. ☐Do not agree.
Q5. **Comment:**	
Q6. **Non-Consequential Load Loss:** Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.	☒Agree. ☐Do not agree.
Q6. **Comment:**	

Q7. **Planning Assessment:** Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.	☐Agree. ☐Do not agree.
Q7. **Comment:**	
Q8. **Planning Events:** Events which require Transmission system performance requirements to be met.	☐Agree. ☐Do not agree.
Q8. **Comment:**	
Q9. **Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.	☐Agree. ☒Do not agree.
Q9. **Comment: This definition mixes the use of the word "plant" and "generator" which have two different meanings. Suggest re-naming as Generator Stability Study and allow the study of multiple generators at a single site as a plant. The use of "generator" vs. "plant" should also be consistent throughout the standard.**	
Q10. **System Stability Study:** Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.	☐Agree. ☐Do not agree.
Q10. **Comment:**	
Q11. **Year One:** The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.	☐Agree. ☒Do not agree.
Q11. **Comment: Suggest replacing the words "annual studies" with "Planning Assessment".**	

B. Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the

rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Yes ☐ No ☐
Comment: Sensitivity cases do not consider/mention new transmission facilities additions. Although the Transmission Planner should have the ability to determine appropriate sensitivities, system performance based on the delay of new transmission facilities should be considered (may be covered under R2.1.3.3 but could be more explicit).

Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a “reasonably stressed” case?

Yes ☐ No ☒
Comment: The Transmission Planner should have the ability to determine appropriate sensitivities based on changes to the assumptions within the study. However, those sensitivities should be developed in an open transmission planning process consistent with the transmission planning principles within FERC Order 890.

Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Yes ☒ No ☐
Comment:

Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Yes ☒ No ☐
Comment: The standard should require long-term sensitivity studies to the extent that the open transmission planning process within FERC Order 890 identifies the need for the sensitivities.

C. Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Yes ☒ No ☐
Comment: The effect of DSM should be considered in corrective action plans to the extent that DSM can reduce overall load growth and change the timing of new transmission facilities.

Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Yes ☒ No ☐
Comment: It is difficult to fully prescribe a methodology to define a "study area". It is most appropriate for the Transmission Planning to develop study areas based on and consistent with the transmission planning principles within Order 890.

Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Yes ☒ No ☒
Comment: If the standard makes a differentiation between "committed" and "proposed" projects, definitions for each, within the standard itself, are necessary. Within the context of R2.7, it is not clear what impact the differentiation between "committed" and "proposed" has on the requirement itself. R2.7 requires Corrective Action Plans to address deficiencies within the performance analysis of the events in Table 1 and Table 2. A fundamental underpinning of R2.7 should be that Corrective Action Plans are developed consistent with the transmission planning principles of Order 890.

Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Yes ☒ No ☐
Comment: As stated in response to Q18, it is unclear why the differentiation between "committed" and "proposed" is actually necessary. The standard must allow flexibility, so that the evolution of a Corrective Action Plan can occur within the context of the transmission planning principles of FERC Order 890.

D. Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

Event	Agree or Disagree	Comment
Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV	☐Agree. ☒Do not agree.	It is not clear why the standard has established 300 kV as the differentiation point between allowing non-consequential load loss and not allowing it. The standard has established different planning requirements for different voltage levels without establishing why the differentiation is necessary. While transmission facilities over 300 kV in some areas of the country may be considered the "backbone", it is not universally applicable; in some areas, 230 kV and even 138 kV represent the "backbone" of the transmission system. The standard should not bisect the transmission system and apply two

		different planning requirements without clearly establishing why the differentiation is necessary. Additionally, Table 1 needs to clarify the use of the term "Firm Transfers" and the interruption of "Firm Transfers" as an acceptable response to an event. "Firm transfers" is not a standard transmission service offering under the ProForma OATT. The standard must be consistent with service types defined under the ProForma OATT. Suggest that the phrasse "Firm Transfers" be replaced with "Firm Transmission Service consisting of Point-to-Point and Network Integration Transmission Service"
Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit	☐Agree. ☒Do not agree.	See response to Q20.
Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV	☐Agree. ☒Do not agree.	See response to Q20
Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer	☐Agree. ☒Do not agree.	See response to Q20

[1]System adjustment can be manual or automatic.

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Yes ☐ No ☐
Comment: See response to Q20

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Yes ☐ No ☐
Comment: See response to Q20

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

Event	**Agree or Disagree**	**Comment**
Q26. P4-1: Loss of a Generator followed by System adjustment[1] followed by loss of another Generator	☒Agree. ☐Do not agree.	It is inappropriate to rely on Non-consequential loss of load as an ultimate Corrective Action Plan for this event. However, non-consequential load loss can provide interim relief until such time as the Corrective Action Plan is actually constructed and in-service.
Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line	☒Agree. ☐Do not agree.	See response to Q26.
Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit	☒Agree. ☐Do not agree.	See response to Q26.
Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer	☒Agree. ☐Do not agree.	See response to Q26.

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Yes ☒ No ☐
Comment:

[1] System adjustment can be manual or automatic

E. Stability

Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Yes ☒ No ☐
Comment:

Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Yes ☒ No ☐
Comment:

Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of extreme events? If not, please explain.

Yes ☒ No ☐
Comment:

Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Yes ☒ No ☐
Comment:

Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Comment:

F. Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Yes ☒ No ☐
Comment:

Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Yes ☒ No ☐
Comment: The use of RAS or SPS should not constitute a long-term Corrective Action Plan to address deficiencies. The use of RAS and SPS should be limited to that period of time necessary to place facilities in-service to address the deficiency.

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Yes ☒ No ☐
Comment: The use of RAS or SPS should not constitute a long-term Corrective Action Plan to address deficiencies. The use of RAS and SPS should be limited to that period of time necessary to implement expansion of facilities to address the deficiency.

Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Comment: The use of RAS or SPS should not constitute a long-term Corrective Action Plan to address deficiencies. The use of RAS and SPS should be limited to that period of time necessary to implement expansion of facilities to address the deficiency.

Q40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Comment: The use of RAS or SPS should not constitute a long-term Corrective Action Plan to address deficiencies. The use of RAS and SPS should be limited to that period of time necessary to implement expansion of facilities to address the deficiency.

G. General Questions

Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Yes ☐ No ☒
Comment:

Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Yes ☐ No ☒
Comment:

Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Yes ☒ No ☐
Comment: Within R1.1.2, the Planning Coordinator and the Transmission Planner is required to define what constitutes "normal weather patterns" for the purpose of establishing load forecasts. However, the PC and/or TP are not the appropriate entities to establish "normal weather patterns"; the LSEs, who actually develop load forecasts and have the expertise, are the appropriate entities to establish normal weather patterns. Additionally, this requirement should consider requiring the 50/50 probability load forecast from the LSEs.