NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

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

Date of Initial Ballot: July 13 – July 22, 2011

Summary Consideration:

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

Voter	Entity	Segment	Vote	Comment
Brock Ondayko	AEP Service Corp.	5	Affirmative	Comments submitted via electronic form by Thad Ness on behalf of American Electric Power.
Mark B Thompson	Alberta Electric System Operator	2	Affirmative	With respect to R2, Part 2.7.1 which lists system deficiencies and the associated actions needed to achieve System performance, the 3rd and 4th bullet identify the following actions as being acceptable. :Installation or modification of automatic generation tripping as a response to a single or multiple contingency to mitigate Stability performance violations. :Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations. The current Alberta transmission policy does not allow for the tripping or runback of generation for a single contingency; however for multiple contingencies it is acceptable. The AESO will bring TPL-001-2, with any modifications, through the standard development consultation process in Alberta and ultimately to the Alberta Utilities Commission for approval.
Kirit Shah	Ameren Services	1	Negative	(1) Requirement R2.4.1, which addresses dynamic load modeling, has been a cause for concern because of the lack of guidance regarding reasonable induction motor representation as opposed to generic load models. While it is recognized that the effort to simulate the effects of induction motor loads is important, it is premature to include such modeling as part of the requirements for this standard. (2) For Measurements M3 and M4, there is still some question as to what is to be provided as sufficient evidence of a study. It is not clear whether the study results would be sufficient, or whether the entire powerflow, stability, or short circuit effort needs to be documented in a formal study report. For example, it is not clear whether contingency lists used in performing the study work would need to be

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

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				retained as part of the documentation. (3) The standard as written is too prescriptive with regard to critical system conditions which are to be modeled. Such conditions would vary considerably for different systems across the continent. (4) Overall, we believe that this standard does not improve the clarity of what is required, and would give additional occasions for disputes between compliance monitors and various registered entities.
Paul B. Johnson	American Electric Power	1	Affirmative	Comments submitted by Thad Ness on behalf of American Electric Power
Steven Norris	APS	3	Affirmative	Comments submitted.
Robert Smith	Arizona Public Service Co.	1	Affirmative	Comments submitted.
Edward Cambridge	Arizona Public Service Co.	5	Negative	While AZPS generally supports this standard, AZPS cannot support the violation severity levels that are proposed in the recirculation ballot. AZPS believes the time frames set forth in the proposed security levels are unreasonably short (10 days) and should be extended to 30 days between each elevation in severity level. For these reasons, AZPS has changed its vote to “negative.”
John Bussman	Associated Electric Cooperative, Inc.	1	Negative	see comments
Kevin Smith	Balancing Authority of Northern California NCR11118	1	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote ‘b’, that addressed planned or controlled interruption of electric supply for N-1 conditions. Registered Entity’s Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable with the associated cost. This point is captured in footnote #12 of Table 1 in the TPL Standard and is necessary for maintaining SMUD’s Affirmative vote.
Venkataramakrishnan Vinnakota	BC Hydro	2	Negative	Comments submitted.
Patricia Robertson	BC Hydro and Power Authority	1	Negative	Comments submitted
Pat G. Harrington	BC Hydro and Power	3	Negative	Comments Submitted

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	Authority			
Clement Ma	BC Hydro and Power Authority	5	Negative	Comments submitted.
Donald S. Watkins	Bonneville Power Administration	1	Affirmative	comments submitted
Rebecca Berdahl	Bonneville Power Administration	3	Affirmative	BPA comments submitted separately.
Francis J. Halpin	Bonneville Power Administration	5	Affirmative	Comments have been submitted separately.
Brenda S. Anderson	Bonneville Power Administration	6	Affirmative	Comments have been submitted.
Jeanie Doty	City of Austin dba Austin Energy	5	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote ‘b’, regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, a Registered Entity’s Board of Directors, local public utility commission, and/or its customers should determine what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote. Regarding R2 (2.5): The value of annually assessing system stability for years 6-10 is questionable. The requirement for stability assessment in years 6-10 should be limited to new generation interconnections or planned major transmission system improvements with regional impact. The standard should clarify the ‘material changes’ that would necessitate stability planning assessments and documentation. Regarding the R8 requirement to distribute all Planning Assessment results to adjacent Planning Coordinators and Transmission Planners is excessive and cumbersome. Regarding R8, we suggest the following language: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners in accordance with the requirements of the applicable Reliability Coordinator. Any Registered Entity with a reliability-related need may submit a written request for the Planning Assessment results and the

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				Transmission Planner or Planning Coordinator shall provide the latest Planning Assessment results within 30 days of such request.
Gregg R Griffin	City of Green Cove Springs	3	Affirmative	R7 is not needed and administrative in nature. Instead is should say that an entity can use as evidence another entity's study, but not in the requirement and rather in the measures. R8 is ambiguous, does the requirement require submitting the Planning Assessment only after receiving a written request, or automatic distribution to neighboring PCs and TPs without a written request, and to others with a reliability related need following a written request? Table 1, under first heading of "Steady State and Stability", bullet c should be removed since it is duplicative of the standard, and not entirely consistent with the standard (e.g., open to interpretation whereas the standard better clarifies how to study protection system operation)
Bill Hughes	City of Redding	3	Affirmative	Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable and with what associated cost. We believe that this is a local load reliability issue and not a BES concern. This view is captured as footnote #12 that allows loss on Non-Consequential load loss under certain circumstances and is essential in maintaining an affirmative vote.
Nicholas Zettel	City of Redding	4	Affirmative	Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable and with what associated cost. We believe that this is a local load reliability issue and not a BES concern. This view is captured as footnote #12 that allows loss on Non-Consequential load loss under certain circumstances and is essential in maintaining an affirmative vote.
Paul Cummings	City of Redding	5	Affirmative	Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable and with what associated cost. We believe that this is a local load reliability issue and not a BES concern. This view is captured as footnote #12 that allows loss on Non-Consequential load loss under certain circumstances and is essential in maintaining an affirmative vote.
Marvin Briggs	City of Redding	6	Affirmative	Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable and with what associated cost. We believe that this is a local load reliability issue and not a BES concern. This view is captured as footnote #12 that allows loss on Non-Consequential load loss under certain circumstances and is essential in maintaining an affirmative vote.

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Randall McCamish	City of Vero Beach	1	Affirmative	R7 is not needed and administrative in nature. Instead is should say that an entity can use as evidence another entity's study, but not in the requirement and rather in the measures. R8 is ambiguous, does the requirement require submitting the Planning Assessment only after receiving a written request, or automatic distribution to neighboring PCs and TPs without a written request, and to others with a reliability related need following a written request? Table 1, under first heading of "Steady State and Stability", bullet c should be removed since it is duplicative of the standard, and not entirely consistent with the standard (e.g., open to interpretation whereas the standard better clarifies how to study protection system operation).
Jack Stamper	Clark Public Utilities	1	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, the utility's elected board of commissioners should have the determination what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote.
Peter T Yost	Consolidated Edison Co. of New York	3	Negative	Requirement R1.1.5: Delete "and Interchange." The inclusion of other than Firm transactions (e.g. economic transactions in Interchange) in a base power flow case utilized for planning/designing the interconnected system blurs the boundary between reliability issues and purely economic issues. Reliability issues are issues that a Transmission Owner (TO) must address for the purpose of meeting its load demand, and are defined by the application of well established reliability standards and criteria that are based on the electrical characteristics of the interconnected system, but without economic considerations. Instead, economic transactions are types of transactions that a TO may enter into once its load obligations are met, and are evaluated based on economic parameters that are markedly different from the aforementioned reliability criteria (e.g. congestion costs). Modeling all types of transactions in a power flow case without distinction detracts from the accuracy and validity of either assessment (reliability and economic).
Wilket (Jack) Ng	Consolidated Edison Co. of New York	5	Negative	Requirement R1.1.5: Delete "and Interchange." The inclusion of other than Firm transactions (e.g. economic transactions in Interchange) in a base power flow case utilized for planning/designing the interconnected system blurs the boundary between reliability issues and purely economic issues. Reliability issues are issues that a Transmission Owner (TO) must address for the purpose of meeting its load demand, and are defined by the

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				application of well established reliability standards and criteria that are based on the electrical characteristics of the interconnected system, but without economic considerations. Instead, economic transactions are types of transactions that a TO may enter into once its load obligations are met, and are evaluated based on economic parameters that are markedly different from the aforementioned reliability criteria (e.g. congestion costs). Modeling all types of transactions in a power flow case without distinction detracts from the accuracy and validity of either assessment (reliability and economic).
Nickesha P Carrol	Consolidated Edison Co. of New York	6	Negative	Requirement R1.1.5: Delete “and Interchange.” The inclusion of other than Firm transactions (e.g. economic transactions in Interchange) in a base power flow case utilized for planning/designing the interconnected system blurs the boundary between reliability issues and purely economic issues. Reliability issues are issues that a Transmission Owner (TO) must address for the purpose of meeting its load demand, and are defined by the application of well established reliability standards and criteria that are based on the electrical characteristics of the interconnected system, but without economic considerations. Instead, economic transactions are types of transactions that a TO may enter into once its load obligations are met, and are evaluated based on economic parameters that are markedly different from the aforementioned reliability criteria (e.g. congestion costs). Modeling all types of transactions in a power flow case without distinction detracts from the accuracy and validity of either assessment (reliability and economic).
David A. Lapinski	Consumers Energy	3	Negative	We agree with the comments of MISO.
David Frank Ronk	Consumers Energy	4	Negative	We agree with comments submitted by MISO
James B Lewis	Consumers Energy	5	Negative	We endorse the comments of MISO.
Sally Witt	East Kentucky Power Coop.	3	Negative	(1) While the Planning Coordinator and Transmission Planner should share the results of their respective Planning Assessments with entities that have a reliability related need, Requirement R8 doesn’t have a significant impact on reliability. The Violation Risk Factor should be changed to Lower. (2) Footnote 3, which applies to BES Level in Table 1, draws in non-BES facilities. It states that HV is defined as 300 kV and lower voltage systems, which includes all voltages below the traditional 100-kV cutoff for the BES.

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				(3) Requirement R1 could be modified unintentionally and fundamentally change the requirement because R1 references MOD-010 and MOD-012 without a version number. Thus, all future updates to these standards directly modify TPL-001-2 Requirement R1 whether it was intended or not.
Stephen Ricker	East Kentucky Power Coop.	5	Negative	Comments on Project 2006-02 Assess Transmission Future Needs and Develop Transmission Plans Recirculation Ballot (1) While the Planning Coordinator and Transmission Planner should share the results of their respective Planning Assessments with entities that have a reliability related need, Requirement R8 doesn't have a significant impact on reliability. The Violation Risk Factor should be changed to Lower. (2) Footnote 3, which applies to BES Level in Table 1, draws in non-BES facilities. It states that HV is defined as 300 kV and lower voltage systems, which includes all voltages below the traditional 100-kV cutoff for the BES. (3) Requirement R1 could be modified unintentionally and fundamentally change the requirement because R1 references MOD-010 and MOD-012 without a version number. Thus, all future updates to these standards directly modify TPL-001-2 Requirement R1 whether it was intended or not.
Charles B Manning	Electric Reliability Council of Texas, Inc.	2	Negative	ERCOT's comments have been submitted via the online form.
Edward J Davis	Entergy Services, Inc.	1	Affirmative	Commens Submitted
Terri F Benoit	Entergy Services, Inc.	6	Affirmative	'Commits Submitted".
Lee Schuster	Florida Power Corporation	3	Affirmative	Comments Submitted
Luther E. Fair	Gainesville Regional Utilities	1	Affirmative	I do have one point of concern for your consideration; This standard does raise the bar in some areas, most notably for an entity the size of GVL it applies performance requirements for long lead equipment emergency replacement. For example if we don't have the ability to replace a transformer at Parker within a few months of failure, then we would have to demonstrate that we can meet many (but not all) of the same performance criteria without the transformer that we can with the transformer.

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Harold Taylor	Georgia Transmission Corporation	1	Affirmative	All of our concerns have been addressed. Regards, Robert Casey Georgia Transmission Corporation
Ajay Garg	Hydro One Networks, Inc.	1	Negative	Hydro One Networks is casting a negative vote. Other than a few changes related to Footnotes 9 and 12 of Table 1 and VSLs, the other changes in the proposed draft are minor. The concerns of the industry on several important issues have not been sufficiently addressed in this draft. For detailed comments please refer to our submission through the on-line comment form.
David Kiguel	Hydro One Networks, Inc.	3	Negative	Hydro One Networks is casting a negative vote. Other than a few changes related to Footnotes 9 and 12 of Table 1 and VSLs, the other changes in the proposed draft are minor. The concerns of the industry on several important issues have not been sufficiently addressed in this draft. For detailed comments please refer to our submission through the on-line comment form.
Bernard Pelletier	Hydro-Quebec TransEnergie	1	Negative	These are the two major concerns : * In Table 1 footnote 3 : Again, the definition of EHV facilities shoud be changed to something like : Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as those representing the backbone of the System, generally at voltage greater than 300 kV, and high voltage (HV) Facilities defined as those not representing the backbone of the System, as determined by the Planning Coordinator and approved by Regional Entity. * In Table 1 b : "Consequential Load Loss as well as generation loss is acceptable as a a consequence of any event excluding P0". We should also add Firm Transmission Services Loss is also acceptable (particularly in P1 Loss of a single pole of a DC line for which the transfer is reduced accordingly to the remaining pole capability). "
Tino Zaragoza	Imperial Irrigation District	1	Affirmative	Comments provided
Jesus S. Alcaraz	Imperial Irrigation District	3	Affirmative	IID submits a Affirmative vote with comments.
Kim Warren	Independent Electricity System Operator	2	Affirmative	We thank the drafting team for considering the concerns and suggestions submitted with our previous ballot. We reiterate our view that we have no issues with the standard per se and we agree that the current draft is a significant improvement over the currently approved TPL-001 through TPL-004 standards. We recognize that it is necessary to move forward with this

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				important work. The uncertainties created as a result of the evolving BES definition and BES Exception Process, as well as regulatory review of the TPL-001-1 Footnote 'b' revision still persist and will not go away for some time to come. These are significant parallel developments that will define applicability of the TPL standard (and all NERC standards) and establish performance requirements. We do however believe that this lingering uncertainty is insufficient grounds for us to vote against a standard we otherwise fully support.
Michael Moltane	International Transmission Company Holdings Corp	1	Affirmative	Comments submitted.
Kathleen Goodman	ISO New England, Inc.	2	Negative	Please see the comments submitted along with this ballot.
Larry E Watt	Lakeland Electric	1	Negative	LAK appreciates the hard work of the Standard Drafting team and applauds the significant improvement of clarity of the draft standard. FMPA believes we are almost there, but, there are a number of issues left to resolve. Issues that Cause FMPA to Recommend a Negative Vote A. Spare Equipment, R2.1.5 - The requirement reaches beyond the FERC directive. The directive was: "Accordingly, the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy." So, the directive is only to address planned outage, not unplanned outages. Also note that the applicability to GSUs is ambiguous. "Transmission" is defined as: "An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems." Is the "point of supply" the generator terminal, or the GSU high side terminal? B. Table 1, under first heading of "Steady State Only", bullet i is open to interpretation. Many utilities use steady state P-V analyses to study voltage stability and design UVLS systems in apart around those steady state analyses. Would this bullet essentially eliminate P-V and Q-V studies and the related use of UVLS?
Martyn Turner	Lower Colorado River Authority	1	Affirmative	1. R2 (2.5): The requirement for stability assessment in years 6-10 should be limited for new generation interconnections or for planned major transmission system improvements that have regional impact. The standard should clarify the 'material changes' that would necessitate stability planning assessments and documentation. 2. R8 requirement to

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				distribute all Planning Assessment results to adjacent PCs and TPs are excessive and cumbersome. Regarding R8, LCRA TSC suggests the following language: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners in accordance with the overseeing Reliability Coordinator requirements. Any functional entity that has a reliability related need and submits a written request for the Planning Assessment results, the Transmission Planner and Planning Coordinator shall provide the latest Planning Assessment results within 30 days of such request.
Tom Foreman	Lower Colorado River Authority	5	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote ‘b’, regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, board of directors/Public Utility should have the determination what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote. 1. R2 (2.5): The value of assessing system stability for years 6-10 is questionable. Stability studies should be conducted for new generation interconnections or for planned major transmission system improvements that have regional impact. 2. R8 requirement to distribute all Planning Assessment results to adjacent PCs and TPs are excessive and cumbersome. Regarding R8, LCRA suggests the following language: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners in accordance with the overseeing Reliability Coordinator requirements. Any functional entity that has a reliability related need and submits a written request for the Planning Assessment results, the Transmission Planner and Planning Coordinator shall provide the latest Planning Assessment results within 30 days of such request.
Brad Jones	Luminant Energy	6	Negative	Our most significant concerns are related to the following: (1) The requirements for Sensitivity Analysis are not stringent enough. (2)Studies should include variations in the duration and timing of transmission outages. “Anticipated” outages should be included in the studies and not just “known” transmission outages. It is our experience that only including “known” outages drastically under represents the actual number of transmission outages. (3) Major equipment outages lasting three or more months, as a result of Spare equipment strategies should be included in studies. The time limit of one year as specified in the Standard is too lax. Specific suggested language: 1.1.2. Known outage(s) of generation or

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				Transmission Facility(ies) with a duration of at least six months or any known outage(s) of generation or Transmission Facility(ies) that will extend into the high stress period of the BES. 2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies (as indicated in Requirement R2, Part 2.6, as follows). Qualifying studies shall include the following conditions: Add language between 2.1.3 and 2.1.4 to account for generation limitations due to Ancillary Services. Suggested wording: All planning studies must recognize and make provision for secure delivery of each of the Ancillary Services (eg Operating Reserve). In no case shall these studies double count capacity as being available for congestion management and Ancillary Services unless processes are in place to allow for location specific deployment of these Ancillary Service reserves for congestion management purposes. 2.1.4 (bullet 7) Duration and timing of anticipated Transmission outages such as required maintenance activities. 2.1.4 (bullet 8 added) Reasonable variations of anticipated generator availability after accounting for equivalent forced outage rate. 2.1.5 If an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that would cause an outage of three months or more, (such as a transformer) the impact of this outage on System performance shall be studied. 2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: o Load level, Load forecast, or dynamic Load model assumptions. o Expected transfers. o Expected in service dates of new or modified Transmission Facilities. o Reactive resource capability. o Generation additions, retirements, or other dispatch scenarios. o Duration or timing of anticipated Transmission outages such as required maintenance activities. o Reasonable variations of anticipated generator availability after accounting for equivalent forced outage rate. 2.4.4. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled. 2.4.5 If an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that would cause an outage of three months or more, (such as

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				a transformer) the impact of this outage on System performance shall be studied.
Joe D Petaski	Manitoba Hydro	1	Negative	Please see Manitoba Hydro's comments submitted in the formal commenting period.
Greg C. Parent	Manitoba Hydro	3	Negative	Please see Manitoba Hydro's comments submitted in the formal commenting period.
S N Fernando	Manitoba Hydro	5	Negative	Please see Manitoba Hydro's comments submitted in the formal commenting period.
Daniel Prowse	Manitoba Hydro	6	Negative	Please see Manitoba Hydro's comments submitted in the formal commenting period.
Terry Harbour	MidAmerican Energy Co.	1	Affirmative	Resolve the conflict between R2 and other requirements in the TPL standards by replacing the term, "System" with "BES" in various places throughout the standard when the reference should not be to the collective generation, transmission, and distribution systems, which is the definition of the NERC Glossary term, "System". These locations are: R2.1.4, R2.1.5, R2.4.3, R2.6.2, R2.7, R2.7.1, R2.7.4, R2.8.1, R2.8.2, R3.5, R4.5, R5, and R6
Thomas C. Mielnik	MidAmerican Energy Co.	3	Affirmative	Resolve the conflict between R2 and other requirements in the TPL standards by replacing the term, "System" with "BES" in various places throughout the standard when the reference should not be to the collective generation, transmission, and distribution systems, which is the definition of the NERC Glossary term, "System". These locations are: R2.1.4, R2.1.5, R2.4.3, R2.6.2, R2.7, R2.7.1, R2.7.4, R2.8.1, R2.8.2, R3.5, R4.5, R5, and R6.
Marie Knox	Midwest ISO, Inc.	2	Negative	Comments. Regarding Requirement 8, we still do not believe that there is significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entity or if a documented response to Planning Assessment comments is not provided within 90 days of a request. Requirement 8 is an administrative requirement that adds little to improve reliability. We recommend that the VRF for Requirement 8 remain "Low", rather than be changed to "Medium". We also believe that the standard is too prescriptive as to what critical system conditions must be modeled, as these conditions vary considerably from system to system and within large systems. Table 1-Steady State and Stability Performance Planning Events, Category P5, includes "non-redundant" relay in the Event column. It is unclear if the SDT's intent is to provide distinction between a

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				back-up relay and a redundant relay. We still believe that a definition for the term “non-redundant” should be provided along with the standard.
Richard Burt	Minnkota Power Coop. Inc.	1	Negative	In general, MPC feels that this standard has some organizational issues and is unclear in many areas. General comments include the following: 1. Use of the word "stability" should be qualified as "dynamic stability" or "transient stability" to avoid confusion with small signal stability or voltage stability. 2. The term "Planning Events" should be relabeled. It's not descriptive enough. Somehow it should be identifiable as being "more likely to occur than Extreme Events." 3. There are numerous forward and backward references between the different requirements, e.g. between R4.1 and R4.4. I see no reason why these isolated sections can't be put under the same requirement. For instance, move the text of R4.4 to R4.1, and move the text of R4.5 to R4.2. 4. There are numerous references to "more severe System impacts" e.g. R3.4. This is vague unless there is some sort of definition included to quantify severity of impacts. The following comments correlate to specific requirements in the new TPL standard. R2.1.5 Need a definition of "major Transmission equipment." It is too open-ended otherwise. R2.7 What is meant by "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with ... 2.1.4 and 2.4.3"? Does it mean that if we can only find one condition that's problematic, we don't need a CAP? R2.7.2 What is meant by "multiple sensitivity studies"? R2.7.3 There should be further explanation of things that qualify as being "beyond the control of the Transmission Planner"? R4.1.2 Need more clarity on "its directly connected Facilities". R5 It's not clear what's meant by "post-Contingency voltage deviations". Why wouldn't they just be voltage limits instead of voltage deviations? Table 1 The notes at the beginning of Table 1 should be labeled as performance requirements or something similar, for convenient reference in discussion and reports. Perhaps they should be in a separate list rather than part of Table 1 itself. The Extreme Events list should be in a separate Table, not part of Table 1. In Table 1 footnote 13, it may be better to describe the protective system functions, such as "protective relays, associated communications, and auxiliary tripping outputs" instead of listing relay types.
Spencer Tacke	Modesto Irrigation District	4	Negative	Both Sections 2.1.4 (seven sensitivities) and 2.4.3 (five sensitivities) require sensitivity studies to be run for all planning events and for all years specified , which increases the number of required studies beyond a reasonable and manageable limit. Also, both Section 2.1.4 and 2.4.3

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				specify that running studies over "...a range of credible conditions that demonstrate a measurable change in System response (performance)." must be completed, yet using "credible conditions" and also "demonstrating a measurable change in System response (performance)", may be mutually exclusive. "Measurable change in System response (performance)" is open to a broad interpretation, which increases the risk that the auditor may very likely interpret it differently than the utility system planner. The definition of the extreme events that have to be analyzed has been made nebulous, where in the existing standards they are quite specific. Requirement 2.1.5 requires the modeling of the loss of any system element that does not have a back-up or spare available sooner than 1 year, as part of the system normal state. It is not clear why using 1 year of loss of use for a system element is being used as the triggering point requiring further system enhancements. Thank you.
Mike Avesing	Muscatine Power & Water	5	Affirmative	no comments
Saurabh Saksena	National Grid	1	Affirmative	Comments submitted.
Tony Eddleman	Nebraska Public Power District	3	Negative	Comments submitted through electronic comment form.
Don Schmit	Nebraska Public Power District	5	Negative	Comments have been submitted by NPPD.
Randy MacDonald	New Brunswick Power Transmission Corporation	1	Negative	Foot Note 12: Rather than requiring planning entities to have a open and transparent planning stakeholder process, which could require significant costs and administration, the foot note should focus on ensuring that affected loads/entities are aware of the possible risks of load loss and alternatives and provide for affected stakeholder feedback
Alden Briggs	New Brunswick System Operator	2	Negative	See NBSO submitted comments
Gregory Campoli	New York Independent System Operator	2	Negative	Comments were provided

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Alan Adamson	New York State Reliability Council	10	Negative	1. In R1.1.5, known commitments for Firm Transmission Service, plus other Interchange that does not violate reliability constraints - it is imperative to model other Interchange after accounting for all existing and planned Firm Transmission Service to ensure that reliability-based transactions are not confused with economic interchange. 2. In R2.2.5, the current requirement language can be interpreted to require evaluation of the simultaneous unavailability of multiple long-lead-time components. Also, as a transformer outage is already evaluated as part of category P6 in Table 1, additional studies should not be required; however, spare equipment strategies could be assessed in the context of the planning assessment. 3. In R2.2, the language in this requirement is materially inconsistent with R2.1, unnecessarily requiring a current study.
Guy V. Zito	Northeast Power Coordinating Council, Inc.	10	Affirmative	NPCC will be submitting a list of comments.
David Boguslawski	Northeast Utilities	1	Negative	Footnote 7 It appears there is a discrepancy between Footnote 7 and Event P2-1. Footnote 7 could be eliminated by rewording Event P2-1 as follows: “Opening one end of a line section w/o a fault”. Footnote 12 NU continues to disagree with the language for Footnote 12 (formerly Footnote b) - Specifically NU believes that the revised language of Footnote 12 suggests that non-consequential demand interruption (load that is not directly served by the elements removed from service as a result of the contingency) could be used to mitigate reliability concerns arising from NERC Category B contingency events (i.e., single element contingencies). This language seems to encourage operational workarounds and adds burdens for operators of the system. NU believes this is not consistent with planning a highly reliable bulk electric system and thus does not support this weaker language”. Requirement R1, Part 1.1.6 The phrase "required for Load" should be deleted as this confuses the issue. Requirement R2, Part 2.2 The language of Requirement R2 Part 2.2 seems to suggest that current annual studies are always required for the long-term steady state assessment. This may have been an oversight, for consistency Requirement R2 Part 2.2 should be modified to similarly read as Requirement R2, Part 2.1. Requirement R3, Part 3.3.1 NU feels that the last sentence of Requirement R3, Part 3.3.1 should be removed since this is handled by PRC-023. Line ratings are addressed by PRC-023 which requires coordination with the Reliability Coordinator. NU suggests the removal of the following sentence: “Tripping of Transmission elements

Voter	Entity	Segment	Vote	Comment
				where relay loadability limits are exceeded." General comment NU believes that a standard should contain statements and requirements that are direct and measurable. TPL-001-2 should not be an exception to this rule. Therefore, statements like "An objective" which appears in Footnotes 9 and 12 shall not be used.
Joseph O'Brien	Northern Indiana Public Service Co.	6	Affirmative	see comment form
John H Hagen	Pacific Gas and Electric Company	3	Affirmative	prior comments have been addressed
John C. Collins	Platte River Power Authority	1	Negative	Stability requirements R4.1.2, along with the second and third bullets of R4.3.1, could be misunderstood to require the development of comprehensive relaying models for all Facilities represented in the stability model. These requirements should be made clear that Stability studies are to simulate the effects of relaying (tripping certain Facilities) and not require relaying models to trigger and cause the effects.
Terry L Baker	Platte River Power Authority	3	Negative	Stability requirements R4.1.2, along with the second and third bullets of R4.3.1, could be misunderstood to require the development of comprehensive relaying models for all Facilities represented in the stability model. These requirements should be made clear that Stability studies are to simulate the effects of relaying (tripping certain Facilities) and not require relaying models to trigger and cause the effects.
Pete Ungerman	Platte River Power Authority	5	Negative	Stability requirements R4.1.2, along with the second and third bullets of R4.3.1, could be misunderstood to require the development of comprehensive relaying models for all Facilities represented in the stability model. These requirements should be made clear that Stability studies are to simulate the effects of relaying (tripping certain Facilities) and not require relaying models to trigger and cause the effects.
Daniel W. O'Hearn	Powerex Corp.	6	Negative	Powerex has submitted a negative ballot for Draft #6 of Standard TPL-001 because Powerex has concerns regarding Footnotes 9 and 4 that need to be addressed. Details of our concerns are summarized below. Background: The work that transmission planners do to ensure Firm Transmission Service is tremendously important for the reliability of the Bulk Electric System and forms a key part of the foundation upon which system operators and energy market participants interact. As a Purchasing-Selling Entity, Powerex is primarily concerned about Footnote 9 that conditions when interruption of Firm Transmission Service may allowed. We believe

Voter	Entity	Segment	Vote	Comment
				that the goals of maintaining system reliability and enhancing market participation will both be best served if the conditions for interrupting Firm Transmission Service become clear and unambiguous in the TPL-001-2 Standard. In our experience, Transmission Providers have different interpretations of the TPL-001 Performance Table and because of latitude previously granted by Footnote B have different perspectives of when Interuptions of Firm Transfers is acceptable. Below we describe the two interpretations using the language of the proposed TPL-001 standard. Interpretation #1: Following loss of the most critical transmission element under stressed conditions, the transmission provider plans to supply the forecast peak loads and Firm Transmission Service indefinitely. o Typically this is achieved by assuming that the System Operators would, within a few minutes of the P1 Single Contingency, curtail all non-firm transmission service and then arm Special Protection Schemes that could result in Interruption of Firm Transmission Service or Non-Consequential Load Loss in the event of a P6 Multiple contingency. Interpretation #2: Following loss of the most critical transmission element under stressed conditions, the transmission provider plans to supply the forecast peak loads indefinitely but may curtail all Firm Transmission Service within 20 minutes if required. o Typically this occurs on systems where there are no Special Protection Schemes to address P6 Multiple contingencies, consequently, the transmission planners assume that curtailment of all non-firm AND as much Firm Transmission Service as required will occur within ~20 minutes of the P1 Single Contingency because the Operators must prepare their transmission system to withstand the next worst contingency. Currently, Purchasing-Selling Entities must plan for situations where they could see their Firm Transmission Service on certain paths curtailed within 20 minutes of a P1 contingency. The less stringent interpretation of the TPL-001 Performance Table that allowed a P1 contingency to change into a P6 contingency within the same operating hour, has resulted in situations where the Firm Transmission Service for inter-regional transfers face significantly greater risks of interruption than the Firm Transmission Service provided to local Load Serving Entities. Powerex recommends that the Standards Drafting Team revise TPL-001 such that all Transmission Planners will know that they should plan for Firm Transmission Service to be sustained indefinitely following P1 contingencies. Specific Comments on TPL-001-2: Footnote 9: Deviation from the Approved Footnote B Powerex believes that the Footnote B, as approved by the NERC Board of Trustees on February 17, 2011, is more stringent than the previous Footnote B and

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				will have the effect of ensuring that Firm Transmission Service can be sustained indefinitely following P1 contingencies. The key difference of the proposed Footnote 9 is that it adds the phrase “as a System adjustment” to the approved version of Footnote B. We believe this addition would cause the practice of curtailing Firm Transmission Service within 20 minutes of P1 contingencies to continue. Consequently, we recommend that the proposed Footnote 9 maintain the approved wording as follows: Footnote 9: An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed (deletion)[as] a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch.... For consistency, Table 1 should also be modified to remove the Footnote 9 reference from the Initial Condition Column for the P3-Multiple Contingency and P6 Multiple Contingency Categories. Footnote 9: Clarity on what is meant by “Resources obligated to re-dispatch” It is unclear to many parties what is meant by an obligation to re-dispatch. Some interpret this as a right to direct the Source to curtail energy scheduled on Firm Transmission Service. Our belief is that “an obligation to re-dispatch” should correspond to a formal agreement with a Generation Owner, located on the load side of a transmission constraint, to resupply the load that had been receiving energy from a remote source before the Firm Transmission Service was curtailed. Consequently, we recommend that Footnote 9 be revised as follows: Footnote 9: ..... a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch [to ensure uninterrupted energy supply to the Load-Serving Entity(ies)], where it can be demonstrated that Facilities, internal and external to the Transmission Planner’s planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss.... Footnote 4: Conditional Firm Transmission Service Footnote 4: “Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.” In a sense, offering conditional firm transmission service is analogous to selling land in a known flood plane - this can be a perfectly acceptable option provided all parties involved in current and future transactions can quantify the risks and manage them appropriately. There needs to be coordination between the planners, operators and marketers to ensure that the conditions that could lead to curtailment of Conditional Firm Transmission Service are understood and the associated

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				risks properly managed. We are concerned that in the absence of coordination, specifically additional requirements included in the BAL and INT standards, energy that is scheduled on conditional firm could actually be marketed as firm and as a result the counterparties to some transactions may not be aware of the curtailment risks they could face.
John T Sturgeon	Progress Energy	6	Affirmative	"Comments Submitted"
Sammy Roberts	Progress Energy Carolinas	1	Affirmative	Comments submitted.
Sam Waters	Progress Energy Carolinas	3	Affirmative	Comments submitted
Wayne Lewis	Progress Energy Carolinas	5	Affirmative	Comments Submitted
Peter Dolan	PSEG Energy Resources & Trade LLC	6	Affirmative	no comments
Chad Bowman	Public Utility District No. 1 of Chelan County	1	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, board of directors/Public Utility should have the determination what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote.
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Affirmative	"Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, a Registered Entity's Board of Directors, Utility Commission, and/or its customers should determine what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote."
Anthony E Jablonski	ReliabilityFirst Corporation	10	Affirmative	Comments submitted
Tim Kelley	Sacramento Municipal Utility District	1	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', that addressed planned or controlled interruption of electric supply for N-1 conditions. Registered Entity's Board of Directors, state

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				Utilities Commission, and/or its customers should determine what level of service is acceptable with the associated cost. This point is captured in footnote #12 of Table 1 in the TPL Standard and is necessary for maintaining SMUD's Affirmative vote.
James Leigh-Kendall	Sacramento Municipal Utility District	3	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', that addressed planned or controlled interruption of electric supply for N-1 conditions. Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable with the associated cost. This point is captured in footnote #12 of Table 1 in the TPL Standard and is necessary for maintaining SMUD's Affirmative vote.
Mike Ramirez	Sacramento Municipal Utility District	4	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', that addressed planned or controlled interruption of electric supply for N-1 conditions. Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable with the associated cost. This point is captured in footnote #12 of Table 1 in the TPL Standard and is necessary for maintaining SMUD's Affirmative vote.
Bethany Hunter	Sacramento Municipal Utility District	5	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', that addressed planned or controlled interruption of electric supply for N-1 conditions. Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable with the associated cost. This point is captured in footnote #12 of Table 1 in the TPL Standard and is necessary for maintaining SMUD's Affirmative vote.
Claire Warshaw	Sacramento Municipal Utility District	6	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', that addressed planned or controlled interruption of electric supply for N-1 conditions. Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable with the associated cost. This point is captured in footnote #12 of Table 1 in the TPL Standard and is necessary for maintaining SMUD's Affirmative vote.
Robert Kondziolka	Salt River Project	1	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In SRP's view, a Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining Affirmative vote.

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John T. Underhill	Salt River Project	3	Affirmative	"Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In SRP's view, a Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining our Affirmative vote."
Steven J Hulet	Salt River Project	6	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In SRP's view, a Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining our Affirmative vote.
Will Speer	San Diego Gas & Electric	1	Abstain	Clarity of this standard is getting worse. Our earlier comments did not seem impacting. At this point, we believe the existing TPL-001-0.1, TPL-002-0a, TPL-003-0a and TPL-004-0 provide much better clarify for us to comply with the TPL standards.
Rich Salgo	Sierra Pacific Power Co.	1	Affirmative	No additional comments submitted.
Sam Nietfeld	Snohomish County PUD No. 1	5	Affirmative	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, a Registered Entity's Board of Directors, Utility Commission, and/or its customers should determine what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote.
James Jones	Southwest Transmission Cooperative, Inc.	1	Negative	Requirement R1 puts registered entities at compliance risk for failure of a Regional Entity to take action and presents a conflict of interest for the Regional Entity. TPL-001-2 references MOD-010 and MOD-012 in Requirement R1. MOD-010 and MOD-012 require applicable registered entities to supply steady-state and dynamics data, respectively, per the Regional Reliability Organizations (RRO) procedures. MOD-011 and MOD-013 specify the RROs to establish procedures but are "fill-in-the-blank" standards that were not approved by the Commission. Thus, they are not enforceable. Since RROs were the predecessors to the Regional Entities (RE), it is commonly understood the standards that apply to the RRO would now apply to the RE. In summary, the TP and PC/PA are dependent on the

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				RE to have the procedures but there are not penalties for the RE if it does not have them. Since the RE would be enforcing the penalty, it could directly contribute to a penalty that is used to offset its compliance budget. While the Planning Coordinator and Transmission Planner should share the results of its Planning Assessment with entities that have a reliability related need, Requirement R8 is purely administrative, does not have any direct impact on reliability, and, therefore, should be removed. At the very least, the VRF should be changed to Lower. This standard is full of double jeopardy issues. Based on the definition of Planning Assessment, Requirement R2 appears to be intended to document Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon studies and the evaluation and meaning of those study results. R3 and R4 require the TP and PC to conduct the steady-state and dynamic planning studies. Given the document/evidence centric ERO enforcement process, Requirement R3 and R4 have implicit obligations to document the study results. Otherwise, how do you prove you complied with R3 and R4? Thus, failure to have a planning assessment documenting your results will result in a simultaneous violation of R2, R3 and R4. In fact, both R3 and R4 even require studies to be completed according to Parts 2.1 and 2.2 for R3 and Parts 2.4 and 2.5 for R4. This further contributes to double jeopardy potential and blurs the line between assessment and study. Footnote 3 which applies to BES Level in Table 1 draws in non-BES facilities. It states that HV is defined as 300 kV and lower voltage systems which includes all voltages below the traditional 100-kV cutoff for the BES. TPL-001-2 Requirement R1 could be modified unintentionally and fundamentally change the requirement because R1 references MOD-010 and MOD-012 without a version number. Thus, all future updates to these standards directly modifies TPL-001-2 Requirement R1 whether it was intended or not. Generally, it is bad form to reference another standard for these reasons.
Larry Akens	Tennessee Valley Authority	1	Negative	1. TVA is concerned about the additional studies, modeling, and projects that must be performed to meet this proposed standard. TVA believes that this amount of work will have little overall improvement on the reliability of the BES. 2. TVA believes that the 7 year implementation plan allowed for “Raising the bar” facilities does not allow sufficient time for TVA to construct the required new facilities. TVA average time for constructing a new 500-kV line can be up to 10 years, given the lead time on ROW and following all NEPA requirements. TVA does understand that the team has language (R2.7.3) regarding the TP or PC inability to get the projects

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				completed through no fault of its own; however, there is no safeguard that the entity will be found non-compliant if all the work cannot be accomplished in this time frame. 3. TVA believes that the footnotes b and c that allow for local load drop in the current TPL standards should still be allowed. TVA understands that this is addressed in FERC Order 693; however, the capital improvements to fix many of these issues will have little overall reliability gain for the Bulk Electric System. TVA believes that this is a local load reliability issue and not a BES concern. 4. TVA is concerned that no generating unit shall pull out of synchronism for Planning Event P1, while the standard does allow generator runback/tripping for the same event. TVA believes that this requirement is overly burdensome without providing any material improvement in system reliability. Does distributed generation have to meet the same requirements for not pulling out of synchronism as a large nuclear unit? 5. The Implementation Plan should include a five-year delay in the effective date for short circuit studies (R2 parts 2.3 and 2.8) since these studies are a new TPL requirement and are not required in the current version 0 standards.
Ian S Grant	Tennessee Valley Authority	3	Negative	TVA appreciates the work of the ATFN drafting team over the last several years in drafting this new standard. TVA does have concerns on several issues we believe should be corrected as we move forward with this standard. Therefore TVA is voting “Negative” on this proposed standard due to the following issues: 1. TVA is concerned about the additional studies, modeling, and projects that must be performed to meet this proposed standard. TVA believes that this amount of work will have little overall improvement on the reliability of the BES. 2. TVA believes that the 7 year implementation plan allowed for “Raising the bar” facilities does not allow sufficient time for TVA to construct the required new facilities. TVA average time for constructing a new 500-kV line can be up to 10 years, given the lead time on ROW and following all NEPA requirements. TVA does understand that the team has language (R2.7.3) regarding the TP or PC inability to get the projects completed through no fault of its own; however, there is no safeguard that the entity will be found non-compliant if all the work cannot be accomplished in this time frame. 3. TVA believes that the footnotes b and c that allow for local load drop in the current TPL standards should still be allowed. TVA understands that this is addressed in FERC Order 693; however, the capital improvements to fix many of these issues will have little overall reliability gain for the Bulk Electric System. TVA believes that this is a local load reliability issue and not a BES concern.

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				4. TVA is concerned that no generating unit shall pull out of synchronism for Planning Event P1, while the standard does allow generator runback/tripping for the same event. TVA believes that this requirement is overly burdensome without providing any material improvement in system reliability. Does distributed generation have to meet the same requirements for not pulling out of synchronism as a large nuclear unit? 5. The Implementation Plan should include a five-year delay in the effective date for short circuit studies (R2 parts 2.3 and 2.8) since these studies are a new TPL requirement and are not required in the current version 0 standards.
David Thompson	Tennessee Valley Authority	5	Negative	TVA appreciates the work of the ATFN drafting team over the last several years in drafting this new standard. TVA does have concerns on several issues we believe should be corrected as we move forward with this standard. Therefore TVA is voting “Negative” on this proposed standard due to the following issues: 1. TVA is concerned about the additional studies, modeling, and projects that must be performed to meet this proposed standard. TVA believes that this amount of work will have little overall improvement on the reliability of the BES. 2. TVA believes that the 7 year implementation plan allowed for “Raising the bar” facilities does not allow sufficient time for TVA to construct the required new facilities. TVA average time for constructing a new 500-kV line can be up to 10 years, given the lead time on ROW and following all NEPA requirements. TVA does understand that the team has language (R2.7.3) regarding the TP or PC inability to get the projects completed through no fault of its own; however, there is no safeguard that the entity will be found non-compliant if all the work cannot be accomplished in this time frame. 3. TVA believes that the footnotes b and c that allow for local load drop in the current TPL standards should still be allowed. TVA understands that this is addressed in FERC Order 693; however, the capital improvements to fix many of these issues will have little overall reliability gain for the Bulk Electric System. TVA believes that this is a local load reliability issue and not a BES concern. 4. TVA is concerned that no generating unit shall pull out of synchronism for Planning Event P1, while the standard does allow generator runback/tripping for the same event. TVA believes that this requirement is overly burdensome without providing any material improvement in system reliability. Does distributed generation have to meet the same requirements for not pulling out of synchronism as a large nuclear unit? 5. The Implementation Plan should include a five-year delay in the effective date for short circuit studies (R2 parts 2.3 and 2.8) since these studies are a

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				new TPL requirement and are not required in the current version 0 standards.
Marjorie S. Parsons	Tennessee Valley Authority	6	Negative	TVA appreciates the work of the ATFN drafting team over the last several years in drafting this new standard. TVA does have concerns on several issues we believe should be corrected as we move forward with this standard. Therefore TVA is voting “Negative” on this proposed standard due to the following issues: 1. TVA is concerned about the additional studies, modeling, and projects that must be performed to meet this proposed standard. TVA believes that this amount of work will have little overall improvement on the reliability of the BES. 2. TVA believes that the 7 year implementation plan allowed for “Raising the bar” facilities does not allow sufficient time for TVA to construct the required new facilities. TVA average time for constructing a new 500-kV line can be up to 10 years, given the lead time on ROW and following all NEPA requirements. TVA does understand that the team has language (R2.7.3) regarding the TP or PC inability to get the projects completed through no fault of its own; however, there is no safeguard that the entity will be found non-compliant if all the work cannot be accomplished in this time frame. 3. TVA believes that the footnotes b and c that allow for local load drop in the current TPL standards should still be allowed. TVA understands that this is addressed in FERC Order 693; however, the capital improvements to fix many of these issues will have little overall reliability gain for the Bulk Electric System. TVA believes that this is a local load reliability issue and not a BES concern. 4. TVA is concerned that no generating unit shall pull out of synchronism for Planning Event P1, while the standard does allow generator runback/tripping for the same event. TVA believes that this requirement is overly burdensome without providing any material improvement in system reliability. Does distributed generation have to meet the same requirements for not pulling out of synchronism as a large nuclear unit? 5. The Implementation Plan should include a five-year delay in the effective date for short circuit studies (R2 parts 2.3 and 2.8) since these studies are a new TPL requirement and are not required in the current version 0 standards.
Bernie M Pasternack	Transmission Strategies, LLC	8	Affirmative	Comments submitted
Tracy Sliman	Tri-State G & T Association,	1	Negative	Comments submitted

Voter	Entity	Segment	Vote	Comment
	Inc.			
Janelle Marriott	Tri-State G & T Association, Inc.	3	Negative	Comments submitted formally on Comment Form
John Tolo	Tucson Electric Power Co.	1	Negative	The definition for Near Term Planning Horizon was deleted, but the formal term is used in other sections such as R2.2.1. There should be a linkage to MOD standard (e.g. 028, 029 & 030) definitions such as 13 months, etc.
Brandy A Dunn	Western Area Power Administration	1	Negative	Standard is improved over previous drafts, but would like to see further changes. Please see suggestions and comments provided on the previously submitted Official Comment Form.
Peter H Kinney	Western Area Power Administration - UGP Marketing	6	Negative	See comments from WAPA made on official comment form.
Steven L. Rueckert	Western Electricity Coordinating Council	10	Affirmative	It is unknown at this time what the outcome of the FERC request for additional infomation related to footnote B will be, but if if results in changes to the language of footnote B, that may change our support for this standard.
Liam Noailles	Xcel Energy, Inc.	5	Negative	Xcel Energy's concerns are detailed in the formal comment submission
David F. Lemmons	Xcel Energy, Inc.	6	Negative	Xcel Energy's concerns are detailed in the formal comment submission.
Roger C Zaklukiewicz		8	Negative	Footnote #7: There appears to be a discrepency between Footnote 7 and Event P2-1; therefore, I recommend the elimination of Footnote 7. Footnote #12: I interpret Footnote 12 to suggest that non-consequential demand interruption could be used to mitigate reliability concerns arising from a NERC Category B contingency event (a single element contingency). The approval of such a reliability policy is inconsistent with a inter- or intra-regional or Area transmission plan than ensure the development of a reliable transmission grid. Such wording is unacceptable as it will lead to large scale inter-regional blackouts, similar to experienced in August, 2003. R1- Part 1.1.6: Delete the words "required for load". R2-Part 2.2: Clarify whether the current annual studies must always be performed as part of the long-term steady-state transmission assessment studies. The wording conveys such a requirement; however, it is not clear whether such studies

Voter	Entity	Segment	Vote	Comment
				are in fact required. Such a requirement would not always be necessary and an unwise use of valuable planning resources. R3-Part 3.3.1: Remove the last sentence since it is already addressed by PRC-023; therefore, it is not required in this document.