March 31, 2011

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: ***North American Electric Reliability Corporation,***
Docket No. RM06-16-009

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits this filing in accordance with Section 215(d)(1) of the Federal Power Act ("FPA") and Part 39.5 of the Federal Energy Regulatory Commission's ("FERC") regulations, seeking approval for four revised Reliability Standards as well as the retirement of four existing approved Reliability Standards.

NERC seeks the Commission's approval of the following four revised Reliability Standards contained in **Exhibit A** to this petition: TPL-001-1 - System Performance Under Normal (No Contingency) Conditions (Category A), TPL-002-1b - System Performance Following Loss of a Single Bulk Electric System Element (Category B), TPL-003-1a - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), and TPL-004-1 - System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

This proposal also includes a request that FERC approve the retirement of four existing Reliability Standards:

- TPL-001-0.1 — System Performance Under Normal (No Contingency) Conditions (Category A)
- TPL-002-0b — System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- TPL-003-0a — System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
- TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

The proposed revised Reliability Standards were approved by the NERC Board of Trustees on February 17, 2011. NERC requests that TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1 be made effective in accordance with the effective date provisions contained in the proposed Reliability Standards. NERC further requests approval for the retirement of the existing standards listed above, concurrent with the implementation of TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1.

NERC's petition consists of the following:

- This transmittal letter;
- A table of contents for the entire petition;
- A narrative description explaining how the proposed reliability standards meet FERC's requirements;
- Reliability standards TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1 submitted for approval (**Exhibit A**);
- Standard Drafting Team Roster (**Exhibit B**); and
- The complete development record of the proposed revised Reliability Standards (**Exhibit C**).

Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Andrew M. Dressel
Attorney for North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC	**)**	Docket No. RM06-16-009
RELIABILITY CORPORATION	**)**	

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF FOUR TRANSMISSION PLANNING SYSTEM PERFORMANCE RELIABILITY STANDARDS AND RETIREMENT OF FOUR EXISTING RELIABILITY STANDARDS

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March 31, 2011

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I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC")[1] hereby requests that the Federal Energy Regulatory Commission ("FERC") approve, in accordance with Section 215(d)(1) of the Federal Power Act ("FPA")[2] and Section 39.5 of FERC's regulations, 18 C.F.R. § 39.5, four revised Reliability Standards: TPL-001-1 - System Performance Under Normal (No Contingency) Conditions (Category A), TPL-002-1b - System Performance Following Loss of a Single Bulk Electric System Element (Category B), TPL-003-1a - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), and TPL-004-1 - System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D). NERC also seeks the concurrent retirement of four existing Reliability Standards: TPL-001-0.1 — System Performance Under Normal (No Contingency) Conditions (Category A), TPL-002-0b — System Performance Following Loss of a Single BES Element (Category B), TPL-003-0a — System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

The purpose of these changes is to clarify TPL Table 1, footnote 'b', as directed in FERC Order No. 693.[3]

The NERC Board of Trustees approved these Reliability Standards on February 17, 2011. NERC requests that the Commission approve the proposed Reliability Standards and make them

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1 NERC has been certified by FERC as the electric reliability organization ("ERO") authorized by Section 215 of the Federal Power Act. FERC certified NERC as the ERO in its order issued July 20, 2006 in Docket No. RR06-1-000. 116 FERC ¶ 61,062 (2006) ("ERO Certification Order).
2 16 U.S.C. 824o.
3 *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1797 (2007), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

effective in accordance with the effective date provisions set forth in the Reliability Standards. **Exhibit A** to this filing sets forth the proposed Reliability Standards. **Exhibit B** contains the standard drafting team roster that developed the proposed Reliability Standards. **Exhibit C** contains Stakeholder Comments Received and the Standard Drafting Team Response. **Exhibit D** contains the complete development record of the proposed Reliability Standards.

NERC is also filing these proposed Reliability Standards with applicable governmental authorities in Canada.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

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*Persons to be included on FERC's service list are indicated with an asterisk. NERC requests waiver of FERC's rules and regulations to permit the inclusion of more than two people on the service list.

III. BACKGROUND

a. Regulatory Framework

By enacting the Energy Policy Act of 2005,[4] Congress entrusted FERC with the duties of approving and enforcing rules to ensure the reliability of the Nation's bulk power system, and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215 states that all users, owners and operators of the bulk power system in the United States will be subject to Commission-approved Reliability Standards.

b. Basis for Approval of Proposed Reliability Standards

Section 39.5(a) of FERC regulations requires the ERO to file with the Commission for its approval each reliability standard that the ERO proposes to become mandatory and enforceable in the United States, and each modification to a reliability standard that the ERO proposes to be made effective. The Commission has the regulatory responsibility to approve standards that protect the reliability of the bulk power system. In discharging its responsibility to review, approve, and enforce mandatory Reliability Standards, FERC is authorized to approve those proposed Reliability Standards that meet the criteria detailed by Congress:

> The Commission may approve, by rule or order, a proposed reliability standard or modification to a reliability standard if it determines that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[5]

When evaluating proposed Reliability Standards, the Commission is expected to give "due weight" to the technical expertise of the ERO. Order No. 672 provides guidance on the factors the Commission will consider when determining whether proposed Reliability Standards meet the statutory criteria.[6]

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4 Energy Policy Act of 2005, Pub. L. No. 109-58, Title XII, Subtitle A, 119 Stat. 594, 941 (2005 (codified at 16 U.S.C. § 824o).
5 Section 215(d)(2) of the FPA, 16 U.S.C. § 824o(d)(2) (2000).
6 *See Rules Concerning Certification of the Electric Reliability Organization; Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards, FERC Stats. & Regs*., ¶ 31,204 at PP 320-338 ("Order No. 672"), *order on reh'g*, FERC Stats. & Regs. ¶ 31,212 (2006) ("Order No. 672-A").

c. Basis for Proposed Changes to Reliability Standards

The proposed Reliability Standards, TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1 are intended to ensure that system simulations and associated assessments are conducted periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future system needs. The proposed standards apply to Planning Authorities and Transmission Planners.

The proposed standards represent a significant revision and improvement relative to the current set of enforceable standards. This project focused on clarifying TPL Table 1, footnote 'b', as required in FERC Order No. 693 and as mandated in FERC's subsequent order dated March 18, 2010, setting a deadline for compliance specific to the footnote 'b' clarification originally described in Order 693 ("March 18 Order").[7] On June 11, 2010, FERC issued a subsequent order in response to re-hearing and clarification requests which extended the compliance filing timeline nine months from the original date of June 30, 2010 to March 31, 2011.[8] Addressed herein and discussed in more detail below are the footnote b revisions in response to the FERC directives issued in Order No. 693 and the March 18 Order. TPL Table 1, footnote 'b' appears in all four proposed Reliability Standards, TPL-001-1 - System Performance Under Normal (No Contingency) Conditions (Category A), TPL-002-1b - System Performance Following Loss of a Single Bulk Electric System Element (Category B), TPL-003-1a - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), and TPL-004-1 - System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D). Revised footnote 'b' now:

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[7] *Order Setting Deadline for Compliance*, 130 FERC ¶ 61,200 (2010) at P 2, 10.
[8] *Order Denying Rehearing and Granting Partial Clarification, Denying Request For Stay, And Granting Extension Of Time*, 131 FERC ¶ 61,231 (2010) at P 3.

- Provides a clear and concise description of when interruption of Demand may be utilized within the planning process to address Bulk Electric System ("BES") performance requirements and a description of the process that must be followed; and
- Provides a clear and concise explanation of when curtailment of firm transfers is allowed.

The Standard Drafting Team (SDT) addressed the following directive issued in FERC Order No. 693 which is discussed in greater detail later in this filing:

> Based on the record before us, we believe that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency. The Commission directs the ERO to clarify the Reliability Standard. Regarding the comments of Entergy and Northern Indiana that the Reliability Standard should allow entities to plan for the loss of firm service for a single contingency, the Commission finds that their comments may be considered through the Reliability Standards development process. However, we strongly discourage an approach that reflects the lowest common denominator. The Commission also clarifies that an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances.[9] [Citations omitted]

d. Reliability Standards Development Procedure

NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC *Standard Processes Manual*, which is incorporated into the Rules of Procedure as Appendix 3A.[10] In its ERO Certification Order,[11] FERC found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus satisfies certain of the criteria for approving Reliability Standards.[12]

The Reliability Standards development process is open to any person or entity with a legitimate interest in the reliability of the bulk power system. NERC considers the comments of

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9 Order No. 693 at P 1794.
10 NERC Standard Processes Manual (2010). Available at: http://www.nerc.com/docs/standards/sar/Appendix_3A_Standard_Processes_Manual_20100903_2_.pdf.
11 *Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (2006) at P 250.
12 Order No. 672 at PP 268, 270.

all stakeholders, and an affirmative vote of stakeholders and the NERC Board of Trustees is required to approve a reliability standard before its submission to the Commission.

The proposed Reliability Standards set out in **Exhibit A** have been developed and approved by industry stakeholders using the procedures established in NERC's *Standard Processes Manual*. These standards were approved by the NERC Board of Trustees on February 17, 2011.

IV. JUSTIFICATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARDS

This section summarizes the development of the proposed Reliability Standards TPL-001-—System Performance Under Normal (No Contingency) Conditions (Category A), TPL-002-1b—System Performance Following Loss of a Single Bulk Electric System Element (Category B), TPL-003-1a—System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), and TPL-004-1—System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D). This section also includes evidence that the proposed Reliability Standards meet the criteria for approval set by the Commission, that is, the proposed Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest.

The standard drafting team roster is provided in **Exhibit B**. Stakeholder Comments Received and Standard Drafting Team Response are provided in **Exhibit C**. The complete development record for the proposed Reliability Standards is available in **Exhibit D**. This record includes the draft of the Reliability Standards through the development; the implementation plan; the ballot pool and the final ballot results by registered ballot body members; stakeholder comments received during the development of the Reliability Standards; and how those comments were considered in developing the Reliability Standards.

The purpose of the TPL Reliability Standards is to establish Transmission system planning performance requirements within the planning horizon to develop a BES that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. This project was restricted to the clarification of Table 1, footnote 'b' which appears in all four Reliability Standards, TPL-001-1—System Performance Under Normal (No Contingency) Conditions (Category A), TPL-002-1b—System Performance Following Loss of a Single Bulk Electric System Element (Category B), TPL-003-1a—System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), and TPL-004-1—System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D). No requirements within those Reliability Standards or any other element of those Reliability Standards were altered in any fashion. While footnote 'b' appears in all four of the aforementioned TPL standards, its relevance and practical applicability is limited to TPL-002-1b—System Performance Following Loss of a Single Bulk Electric System Element (Category B).

Upon the implementation of the four preceding proposed standards, the currently effective TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0, are proposed to be retired in their entirety.

The Implementation Plan for these standards requires compliance consistent with the scheduled effective date six months after the first day of the first calendar quarter following applicable regulatory approval depending on the requirement. In those jurisdictions where no regulatory approval is required, all requirements go into effect six months after NERC Board of Trustees adoption.

The proposed revised footnote b for Table 1 is as follows:

> An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

The revised footnote 'b' is intended to address FERC's directives in Order No. 693. Specifically, NERC addressed FERC's instruction to clarify "footnote 'b' in regard to load loss following a single contingency, specifying the amount and duration of consequential load loss and system adjustments permitted after the first contingency to return the system to a normal operating state." [13] However, NERC did not delete in its entirety the ability of an entity "to plan for the loss of non-consequential load in the event of a single contingency."[14] Rather NERC crafted a footnote the meets the Commission's objective while simultaneously meeting the needs of industry and respecting of jurisdictional bounds. No longer can those registered with NERC as Planning Authorities or Transmission Planners plan to interrupt Load under a Category B (N-1) Contingency event unless the registered functions meets the specified conditions detailed in the footnote. NERC's proposed revision to footnote 'b' is an equally effective and efficient alternative to address the Commission's directive that must be given its due weight by FERC.[15]

a. Demonstration that the proposed reliability standard is just, reasonable, not unduly discriminatory or preferential and in the public interest

[13] Order No. 693 at P 1797.
[14] Order No. 693 at P 1794.
[15] Section 215(d)(2) of the FPA, 16 U.S.C. § 824o(d)(2) (2000).

Section 215 of the FPA requires that Reliability Standards be "just, reasonable, not unduly discriminatory or preferential, and in the public interest."[16] In Order No. 672, the Commission identified criteria it will use to analyze proposed Reliability Standards to ensure that the requirements of Section 215 are met. A review of the proposed Reliability Standards for consistency with these criteria is presented below.

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal

> Order No. 672 at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cyber security protection.

Footnote 'b' now specifically establishes the requirements for the limited circumstances when and how an entity can plan on interrupting Demand for Category B Contingencies as well as the process and documentation required.

2. Proposed Reliability Standards must contain a technically sound method to achieve the goal

> Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for

[16] Section 215(d)(2) of the FPA; 18 C.F.R. §39.5(c).

> ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

The proposed footnote contains technically sound methods to achieve the goal of establishing the criteria for the limited circumstances when and how an entity can plan on interrupting Demand for Category B Contingencies.

3. Proposed Reliability Standards must be applicable to users, owners, and operators of the bulk power system, and not others

> Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

The proposed footnote is applicable to users, owners, and operators of the bulk power system, and not others. Specifically, the proposed footnote is applicable to Planning Authorities and Transmission Planners, each clearly a user, owner, or operator of the bulk power system.

4. Proposed Reliability Standards must be clear and unambiguous as to what is required and who is required to comply

> Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

The proposed footnote is clear and unambiguous as to what is required and who is required to comply. The applicability of the proposed Reliability Standards will remain unchanged from the currently existing versions.

5. Proposed Reliability Standards must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation

> Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

The proposed footnote includes clear and understandable consequences. No changes were made to any of the approved VRFs and VSLs.

6. Proposed Reliability Standards must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner

> Order No. 672 at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

The proposed footnote identifies clear and objective criteria to support enforcement in a consistent and non-preferential manner. The language used in the footnote clearly identifies what is expected of the applicable entity.

7. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost

> Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

The proposed footnote achieves its reliability goal effectively and efficiently. The proposed Reliability Standards make use of existing practices in some areas and in others use simple extrapolations of things that applicable entities already do. The reliability goal for the revised footnote should be easily attainable without any undue implementation costs.

8. Proposed Reliability Standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect bulk power system reliability

> Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the

> ERO should not propose a “lowest common denominator” Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

The proposed footnote is more stringent than current requirements with the addition of an open and transparent stakeholder process and the requirement to address stakeholder concerns arising out of that process. Therefore the proposed standards cannot be said to represent the “lowest common denominator” that does not adequately protect bulk power system reliability.

9. Proposed Reliability Standards may consider costs to implement for smaller entities but not at consequence of less than excellence in operating system reliability

> Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a “lowest common denominator” Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

The proposed footnote does not differentiate among entities based on size or cost. The revisions to the Reliability Standards make use of existing practices in some areas and in others use simple extrapolations of things that applicable entities already do. The reliability goal for the revised footnote should be easily attainable without any undue implementation costs and smaller entities should not be unduly affected.

10. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one area or approach

> Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or

> regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

The proposed footnote is designed to apply throughout North America. The footnote as drafted proposes no regional differences or variances.

11. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid

> Order No. 672 at P 332. As directed by section 215 of the FPA, the Commission itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

There is no basis for anticipating that the proposed footnote will adversely affect competition or restrict available transmission capability beyond what is necessary for reliability.

12. The implementation time for the proposed Reliability Standards must be reasonable

> Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, the Commission will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

The proposed footnote changes include a proposed effective date for those standards. As noted above, the proposed footnote is more stringent in several areas. NERC believes the proposed effective date represents a reasonable time frame to allow all entities to adequately prepare for compliance with the footnote. Compliance is already required for Reliability Standards TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.

13. The Reliability Standard development process must be open and fair

> Order No. 672 at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission

NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC *Standard Processes Manual*, which was incorporated into the Rules of Procedure as Appendix 3A. In the ERO Certification Order, FERC found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards.[17] The development process is open to any person or entity with a legitimate interest in the reliability of the bulk power system. NERC considers the comments of all stakeholders and an affirmative vote of stakeholders and the NERC Board of Trustees is required to approve a Reliability Standard for submission to the Commission.

The proposed Reliability Standards set out in **Exhibit A** have been developed and approved by industry stakeholders using the process found in NERC's *Standard Processes Manual*, and were approved by the NERC Board of Trustees on February 17, 2011 for filing with FERC. Therefore, NERC has utilized its approved standard development process in good faith and in a manner that is open and fair.

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[17] *Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (2006) at P 250.

14. Proposed Reliability Standards must balance with other vital public interests

> Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

This footnote is focused on ensuring transmission system planning performance within the planning horizon is met in order to develop a bulk power system that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies. No other environmental, social, or other goals are affected by these proposed standards.

15. Proposed Reliability Standards must consider any other relevant factors

> Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.
>
> Order No. 672 at P 337. In applying the legal standard to review of a proposed Reliability Standard, the Commission will consider the general factors above. The ERO should explain in its application for approval of a proposed Reliability Standard how well the proposal meets these factors and explain how the Reliability Standard balances conflicting factors, if any. the Commission may consider any other factors it deems appropriate for determining if the proposed Reliability Standard is just and reasonable, not unduly discriminatory or preferential, and in the public interest. The ERO applicant may, if it chooses, propose other such general factors in its ERO application and may propose additional specific factors for consideration with a particular proposed Reliability Standard.

An overview of the issues raised in consideration of the proposed standard, included in Exhibit B, is presented in a matrix and demonstrates how industry comments from previous work, as well as directives from Order No. 693, were addressed in this standard development project.

V. VIOLATION RISK FACTORS AND VIOLATION SEVERITY LEVELS

Because this project dealt solely with clarifying the footnote, no changes were made to any of the previously approved VRFs and VSLs.

VI. SUMMARY OF THE RELIABILITY STANDARD DEVELOPMENT PROCEEDINGS

a. Development History

On April14, 2010, NERC received, and the Standards Committee approved, a standards authorization request ("SAR") for Project 2010-11 TPL Table 1 Order. The purpose of the SAR was to clarify TPL Table 1, footnote 'b', as directed in FERC Order No. 693.[18]

The SDT posted the proposed footnote for a 45-day industry comment period in parallel with an initial ballot from April 15, 2010 to May 27, 2010. A quorum of 84.41% was achieved and the proposal garnered an approval of 63.75%. In response, there were 22 sets of comments, including comments from more than 80 different people from approximately 40 companies representing 8 of the 10 industry segments. Comments focused on ambiguity in footnote 'b' and concerns that the footnote was too prescriptive. Stakeholders identified that the terminology used in the proposed footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes: (a) replacing the term 'Load' with 'Demand' and (b) replacing the term 'Firm Transmission Service' with 'firm transfers'.

While the initial ballot result was close to achieving the required approval percentage, it became clear to the SDT from the comments received on the standards that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could

[18] Order No. 693 at P 1797.

be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted.

In order to receive additional industry feedback, NERC held a Technical Conference on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These four questions were:

1. Under what circumstances do you believe the existing footnote 'b' allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote 'b' were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a

process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT received responses indicating:

- Industry believes that interrupting non-consequential Demand for Category B Contingencies was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term 'fringes' was seen as problematic and application at the 'fringes' could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.
- Prohibition on interrupting of non-consequential Demand for Category B Contingencies is not necessary to protect bulk power system reliability and oversight of reliable electric service to end-use customers under these circumstances should be determined by the local regulators.

The SDT reviewed and evaluated the responses and returned to their deliberations attempting to synthesize the existing work with the industry comments to develop a clarification to footnote 'b' to address the Commission's directives. This led to the approach where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process. This open and transparent stakeholder process is seen by NERC, the SDT, and the industry as an enhancement of existing entity processes without the problems associated with the ERO or FERC case-by-case exception process. The SDT believed that this approach addresses industry concerns and the FERC Order 693 directives (and subsequent orders) seeking clarification to footnote 'b' in a way that is an equal and effective method to the statements in Order 693. This revision provides the needed clarification while limiting the circumstances when an entity may interrupt Demand. Placing restrictions on when an entity may interrupt Demand leaves the necessary tools in the hands of the planners while still protecting the interests of end-use customers.

The SDT revised the draft footnote accordingly and re-posted for industry comment from September 8, 2010 to October 8, 2010. This time, 42 sets of comments, including comments from more than 96 different people from approximately 75 companies representing 7 of the 10 Industry Segments were received. Industry response was divided in relation to support for the proposed footnote 'b'. Although there were a number of supporters for the proposed footnote, they were outnumbered by commenters who did not support the changes for various reasons.

The SDT again revised the draft footnote to accommodate industry concerns and posted it for parallel comment and balloting between November 19, 2010 and January 5, 2011. In response to this posting, there were 27 sets of comments, including comments from more than 67 different people from approximately 30 companies representing 8 of the 10 Industry Segments. With a 90.42 percent quorum participating in the ballot, the proposed footnote achieved a weighted segment approval of 88.33 percent. Of the negative votes, 39 were accompanied by comments.

There were five main themes to the comments supplied:

1. The language concerning the stakeholder process wasn't needed.
2. Confusion on the use of the terms "Interruptible" and "DSM.".
3. The preamble to the footnote wasn't appropriate for Reliability Standards.
4. The proposed footnote was not restrictive enough because it allowed interruption of Load.
5. Clarification was needed with respect to the use of curtailment of firm transfers.

The SDT addressed all of the ballot comments and restructured the ordering of the items in the footnote to clarify the intent of the SDT revisions.

The SDT believes that this approach addresses the FERC Order 693 (and subsequent orders) directives concerning the planned use of loss of firm Load for a single Contingency in footnote 'b' in a way that is an equal and effective method to what was proposed by the Commission in Order No. 693. This approach protects bulk power system reliability and ensures that any use of footnote b will be vetted in an open, transparent stakeholder process.

NERC conducted a recirculation ballot from January 26, 2011 through February 5, 2011. With a 93.61 percent quorum participating in the ballot, the proposed footnote achieved a weighted segment approval of 86.54 percent. The NERC Board of Trustees approved the standards during its February 17, 2011 meeting.

VII. <u>CONCLUSION</u>

For the reasons stated above, NERC respectfully requests that the Commission approve four revised Reliability Standards: TPL-001-1 - System Performance Under Normal (No Contingency) Conditions (Category A), TPL-002-1b - System Performance Following Loss of a Single Bulk Electric System Element (Category B), TPL-003-1a - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), and TPL-004-1 - System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk

Electric System Elements (Category D). NERC also seeks the concurrent retirement of four existing Reliability Standards: TPL-001-0.1 — System Performance Under Normal (No Contingency) Conditions (Category A), TPL-002-0b — System Performance Following Loss of a Single BES Element (Category B), TPL-003-0a — System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), as set out in **Exhibit A**, in accordance with Section 215(d)(1) of the FPA and Part 39.5 of FERC regulations. Finally, NERC requests that the proposed Reliability Standards and the retirement of FERC-approved Reliability Standards be made effective in accordance with the effective date provisions set forth in the proposed Reliability Standards.

Respectfully submitted,

<u>/s/ Andrew M. Dressel</u>
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<u>**CERTIFICATE OF SERVICE**</u>

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 31st day of March, 2011.

<u>*/s/ Andrew M. Dressel*</u>
Andrew M. Dressel

Attorney for North American Electric Reliability Corporation

Exhibit A

Reliability Standards Proposed for Approval

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)

2. **Number:** TPL-001-1

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-1_R1 and TPL-001-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised
1	February 17, 2011	Approved by the Board of Trustees	Update

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	 Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c]	 No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	 Yes Yes Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	 No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)

2. **Number:** TPL-001-~~0.~~1

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

    4.1. Planning Authority

    4.2. Transmission Planner

~~**5.Effective Date:** May 13, 2009~~

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-~~0~~1 R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-~~0~~1 R1 and TPL-001-~~0~~1 R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-~~0~~1 R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised

~~**Table I. Transmission System Standards – Normal and Emergency Conditions**~~

~~**Category**~~1	~~**Contingencies**~~Approved by Board of Trustees February 17, 2011	~~**System Limits or Impacts**~~Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D[d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

~~b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is

due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

A. Introduction

1. **Title:** **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. **Number:** TPL-002-1b

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote ‘b’ in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-1_R1 and TPL-002-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	Approved by the Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section - - - - - - - - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - - - - - - - - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-~~0b~~1b

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

~~**5. Effective Date:** Immediately after approval of applicable regulatory authorities.~~

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories~~,~~, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

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R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-~~0~~1 R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-~~0~~1 R1 and TPL-002-~~0~~1 R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-~~0~~1 R3.

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D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	Approved by the Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)

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Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

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D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section - - - - - - - - - - - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - - - - - - - - - - - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

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a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

~~b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12
Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12
Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**
2. **Number:** TPL-003-1a
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
4. **Applicability:**
   - **4.1.** Planning Authority
   - **4.2.** Transmission Planner
5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-1_R1 and TPL-003-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0a	April 23, 2010	FERC approval of interpretation of TPL-003-0 R1.3.12	Interpretation
1a	February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised
1a	February 17, 2011	Approved by the Board of Trustees	

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

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<td>D [d]

Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</td>
<td>3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure):
1. Generator
2. Transmission Circuit
3. Transformer
4. Bus Section
<hr>3Ø Fault, with Normal Clearing[e]:
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<hr>6. Loss of towerline with three or more circuits
7. All transmission lines on a common right-of way
8. Loss of a substation (one voltage level plus transformers)
9. Loss of a switching station (one voltage level plus transformers)
10. Loss of all generating units at a station
11. Loss of a large Load or major Load center
12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required
13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate
14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</td>
<td>Evaluate for risks and consequences.
▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.
▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.
▪ Evaluation of these events may require joint studies with neighboring systems.</td>
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a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

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f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

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TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

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R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

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R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

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MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

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> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

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Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

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A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-~~0a~~1a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

~~5. **Effective Date:** April 23, 2010~~

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

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R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-~~0~~1_R1, the Planning Authority and Transmission Planner shall each:

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R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-~~0~~1_R1 and TPL-003-~~0~~1_R2.

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M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-~~0~~1 R3.

~~**M2.**~~

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D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

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1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

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1.3. Data Retention

None specified.

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1.4. Additional Compliance Information

None.

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2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

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Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0a	April 23, 2010	FERC approval of interpretation of TPL-003-0 R1.3.12	Interpretation
1a	February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

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1a	February 17, 2011	Approved by the Board of Trustees	

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Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

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D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

~~b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

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Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

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Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

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Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

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A. Introduction

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. **Number**: TPL-004-1

3. **Purpose**: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability**:

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote ‘b’ in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority’s and Transmission Planner’s assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-1_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-1_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by the NERC Board of Trustees	
0	April 1, 2005	Effective Date	New
1	February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised
1	February 17, 2011	Approved by Board of Trustees	

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

A. Introduction

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. **Number**: TPL-004-~~0~~1

3. **Purpose**: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability**:

   4.1. Planning Authority

   4.2. Transmission Planner

~~5. **Effective Date:** April 1, 2005~~

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-~~0~~1_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-~~0~~1_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

~~E.~~B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	Approved by the Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised (Project 2010-11)

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

~~b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Exhibit B

Standard Drafting Team Roster

Project 2010-11 TPL Table 1
Drafting Team Roster

Name and Title	Company and Address	Contact Info	Bio
John Odom, Chair Vice President of Planning and Operations	Florida Reliability Coordinating Council, Inc. 1408 N. Westshore Blvd., Suite 1002 Tampa, FL 33607-4512	(813)207-7985 jodom@ frcc.com	John Odom is Vice President of Planning and Operations at the Florida Reliability Coordinating Council (FRCC). John joined FRCC in May, 2005 after 26 years at Progress Energy Corporation (PEF). He is responsible for oversight of all Member Services Activities, including the FRCC standing committees, FRCC Reliability Coordinator, and Planning Authority function. Additionally, he oversees the Regional Entity functions of reliability assessment, situational awareness, training, certification of system operators, and event analysis. From 2001 – 2007, John was the FRCC Representative on the NERC Reliability Assessment Subcommittee (RAS). John is currently the chair of the Assess Future Transmission Needs Standards Drafting Team (AFTNSDT), which is re-writing the existing TPL-001 through TPL-006.
Douglas Hohlbaugh, Vice Chair Standards Development Manager	FirstEnergy Corp. 76 South Main Street 10th Floor Akron, Ohio 44308	(330) 384-4698 hohlbaughdg@ firstenergycorp. com	Doug Hohlbaugh holds a Bachelor of Science in Electrical Engineering from Akron University (1989) and a Professional Engineering license in the state of Ohio. His 20 plus years experience in the electric utility industry has involved the transmission business of FirstEnergy with a focus on transmission planning. His work experience includes various technical positions in transmission and distribution, as well as sales and marketing experience with FirstEnergy's (FE) unregulated energy services Existing responsibilities include the Reliability Standards Development Lead of the FirstEnergy FERC Compliance Department including oversight of newly proposed and/or revised reliability standards governing the bulk electric transmission system. The responsibilities include overseeing and ensuring timely implementation of all new reliability standard development projects at both the North American Electric Reliability Corporation (NERC) and Reliability First Corporation (RFC) having impact on a variety of FE business units which support the reliable operation of the bulk transmission system.
D. Darrin Church Principal Engineer Bulk Transmission Planning	Tennessee Valley Authority 1101 Market Street MR 5G-C Chattanooga, Tennessee 37402-2801	423) 751-6899 (423) 751-3453 Fx ddchurch@tva. gov	Darrin Church is a Principal Bulk Planning Engineer in TVA's Transmission Planning Department. Darrin has 15 years experience in Bulk Transmission Planning along with 5 years previous experience in planning relaying and protection schemes. Responsibilities include insuring reliability of TVA's 500 kV, 230 kV, 161 kV, and 115 kV transmission systems which include initiating capital projects required to maintain an adequate and reliable transmission system per NERC Reliability Standards.

William Harm Senior Consultant	PJM Interconnection, L.L.C. 955 Jefferson Ave Valley Forge Corporate Center Norristown, Pennsylvania 19403-2497	(610) 666-8868 harm@pjm.com	Bill Harm has over 35 years of industry experience with PJM through various assignments involving real time operation, operations planning, and transmission planning. Mr. Harm's current responsibilities involve performance assessment and policy development responsibilities. He either has or continues to represent PJM in various industry forums and groups, including RFC, NERC, and the ISO/RTO forums. He earned a Bachelor and Maters of Science Degree in Electrical Engineering from Drexel University and is a registered professional Engineer in the Commonwealth of PA.
Julius Horvath Director System Planning	Lone Star Transmission, LLC	(512)236-3135 julius.horvath@ lonestar- transmission.co m	Julius Horvath is currently the Director of System Planning at Lone Star Transmission, LLC, in Austin, Texas. Julius has over ten years of utility experience at the Bonneville Power Administration, Wind Energy Transmission Texas, LLC and the Lower Colorado River Authority in Transmission Planning prior to Lone Star. Julius is a Registered Profession Engineer in the State of Texas.
Robert A. Jones Project Manager, Stability Studies	Southern Company Services P.O. Box 2641 Birmingham, Alabama 35291	(205) 257-6148 rajones@ southernco.com	Robert Jones obtained a BSEE degree from the University of Alabama in 1973 and a MSEE degree from University of Alabama – Birmingham in 1978. He has worked for 37 years for Southern Company Services. Eighteen of those years have been in Transmission Planning. The last 15 years, he has been responsible for stability studies for Southern Company.
Brian K. Keel Manager, Transmission System Planning	Salt River Project MS POB100 PO Box 52025 Phoenix, Arizona 85072	602-236-0970 brian.keel@ srpnet.com	Brian Keel has a Bachelor and Master Degrees in Electrical Engineering, specializing in power systems, from the University of Illinois. Brian was employed by Duke Power for over one year and PSI Energy for 8 years. Brian has been at SRP since 1998 and is currently the Manager of Transmission System Planning. Brian has Chaired four groups within WECC mainly concentrating on transmission reliability. Brian is a current member of the NERC TADS Work Group.
R. W. Mazur Manager System Planning Department	Manitoba Hydro 12-1146 Waverly Street P.O. Box 815 Winnipeg, Manitoba R3C 2P4	(204) 474-3113 rwmazur@ hydro.mb.ca	Ronald W. Mazur obtained his Bachelor of Science in Electrical Engineering degree in 1971, and his Masters of Science in Electrical Engineering degree in 1989, both from the University of Manitoba. Ron Mazur is a registered professional engineer with the Association of Professional Engineers and Geoscientists of Manitoba. Ron joined Manitoba Hydro in 1974, where he worked in station design for 5 years, and in system performance (operations) for 6 years, and in system planning since 1986. He is currently the Manager of the System Planning Department responsible for the expansion planning of Manitoba Hydro's transmission system (100 kV and above) and the HVDC system. Ron is a Canadian representative on the NERC Planning Committee, and Chair of the Planning Committee of the Midwest Reliability Organization.
Thomas C. Mielnik Manager Electric System Planning	MidAmerican Energy Co. 106 East Second Street Davenport, Iowa 52808	(563) 333-8129 tcmielnik@ midamerican.co m	Thomas Mielnik has over 37 years experience in Electric Utility Planning. He has been the Manager of Electric System Planning for MEC from 1995 to the present. He was a member of the NERC ATC Working Group from 1996 to 1999 and is a Registered Professional Engineer.

Bernie M Pasternack, President, P.E.	Transmission Strategies 4347 Harborough Rd Upper Arlington, Ohio 43220	(614) 459-5806 bmpasternack@att.net	Bernie Pasternack was employed by the AEP Service Corporation for over 41 years, where he spent his entire career in various aspects of transmission planning and asset management. After retiring from AEP in June 2010, he formed his own consulting practice, providing services to the electric utility industry. He holds BEE and MSEE degrees from Rensselaer Polytechnic Institute and an MBA from Fairleigh Dickinson University. Before retiring from AEP, Bernie was responsible for the planning and management of AEP’s transmission assets. His department provided the analytical and planning services for the entire AEP System, eleven operating companies, and a transmission network consisting of transmission facilities ranging in voltage from 23 kV to 765 kV. This system spans eleven states and three reliabilty regions (RFC, SPP, and ERCOT). Bernie was also responsible for providing input to policy making decisions relative to AEP's transmission strategy and business plan. Bernie directed the analytical and planning services provided to the eleven operating companies. Such services included future system performance appraisal and planning studies, IPP interconnection studies, and all analytical studies dealing with the steady-state and dynamic operation of interconnected power systems. Based on an evaluation of the results of these studies, the Transmission Planning group developed and recommended capital improvement projects and programs for the reinforcement of the AEP System transmission network. In parallel with these efforts, the Transmission Asset Engineering group developed capital rehabilitation programs and set maintenance guidelines to maintain the health of AEP’s transmission assests. During his career, Bernie has made significant contributions to a variety of industry organizations including IEEE, CIGRE, EPRI, EEI, ECAR/RFC, and NERC. He was a member of the EEI Transmission Policy TF and AEP's representative on the Reliability First Corporation Reliability Committee. Bernie has also played an active role in many NERC activities over the past twenty years, including its Planning Committee and a number of its subcommittees, working groups, and standards drafting teams.
Bob Pierce Senior Engineer	Duke Energy 526 South Church Street MC EC10Q Charlotte, North Carolina 28201-1006	(980) 373-6480 bob.pierce@duke-energy.com	Robert (Bob) Pierce is a Consulting Engineer at Duke Energy where he specializes in Bulk System Planning, NERC standards, and FERC regulations. He holds a B.S. in Nuclear Engineering from Pennsylvania State University and a M.S. in Electrical Engineering from the University of North Carolina-Charlotte. Mr. Pierce is a registered Professional Engineer with 13 years Transmission Planning experience and a total of 31 years of power system experience.

Chifong L. Thomas Principal Transmission Planning Engineer	Pacific Gas and Electric Company (now at Bright Source Energy)		Chifong Thomas is currently the Senior Director, Energy Markets and Strategy at Bright Source Energy, Inc. However, at the time of this work effort, she was a Principal Transmission Planning Engineer at Pacific Gas and Electric Company (PG&E). She has more than 39 years of electric utility experience, more than 37 of which is in electric transmission planning. She has both conducted and supervised transmission planning studies to develop plans for the PG&E transmission system from 60 kV to 500 kV. She has participated in developing methodologies, policies and strategic plans, and in contract negotiations. Ms Thomas has also served as an expert witness in various regulatory and judicial forums. She has served on various technical organizations and work groups, including WECC, NERC Standards Drafting Teams, and Industry Advisory Committees of the California Energy Commission and of EPRI. She has also served on the Technical Advisory Committee (Electrical Engineering) to the California Board of Registration for Professional Engineers and Land Surveyors. Ms Thomas holds a Bachelor of Science Degree in Electrical Engineering from Washington State University and is a registered Electrical Engineer in the State of California. She is also a senior member of the IEEE.
Dana Walters Manager Transmission Planning, Process, & Policy	National Grid 40 Sylvan Road Waltham, Massachusetts 01581	781-907-2501 dana.walters@ us.ngrid.com	Dana Walters is a Manager in the Transmission Planning group at National Grid. Mr. Walters has 34 year of experience in the Electric Utility industry. Most of his experience involves various aspects of Transmission Planning. This includes topics such as analytical studies of thermal, stability, short circuit, generator interconnections, and lightning protection. Other areas of experience include involvement in Investment Planning, tariff design, Consulting, Production Cost analysis, and Distribution Planning. In his role as a Transmission Planner, Mr. Walters has been involved in numerous committees and working groups at the NERC, NPCC, and ISO levels. Mr. Walters has a Masters in Engineering Management from Northeastern University and a Bachelor in Electrical Engineering with a focus in Power Systems also from Northeastern University. Mr. Walters is a registered professional engineer in New Hampshire and is a member of IEEE.

Exhibit C

Stakeholder Comments Received and Standard Drafting Team Response

Consideration of Comments on Project 2010-11: TPL Table 1 Order and Comments Submitted with Initial Ballots

The Standards Committee thanks all commenters who submitted comments on the proposed SAR for the TPL Table 1 Order. The SAR proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which requires the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards.

The SAR, implementation plan, and the clean and redline versions to the four TPL standards were posted for a 40-day public comment period from April 15, 2010 through May 27, 2010. Stakeholders were asked to provide feedback on the standards through a special electronic comment form. There were 22 sets of comments, including comments from more than 80 different people from approximately 40 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

The initial ballot for the proposed changes to the four TPL standards was conducted from May 17-27, 2010. The comments submitted with initial ballots and the drafting team's responses to those comments are also contained in this report.

All comments submitted during the comment period and the initial ballot results are posted on the following page:

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Based on stakeholder comments, the drafting team has made some additional changes to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

The following bullet was added to Footnote 'b' to provide the flexibility requested by stakeholders with respect to interrupting Demand, but with appropriate constraints to protect reliability. The >90% demand level was selected to ensure that the number of hours with exposure to demand loss was not unlimited. A 90% demand level is a reasonably stressed case for most systems and the number of hours when peak demands are >90% is a small percentage of the time for most systems. A large percentage of the transmission lines that directly serve distribution customers are 161 kV or lower voltages. Ten percent (10%) of the loading on a high capacity 161 kV transmission line is approximately 50 MW.

- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW

The following bullet was added to Footnote 'b' to clarify that it is acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

The above changes will be noted to stakeholders before the initiation of the recirculation ballot.

The revised Footnote 'b' is:

b) No interruption of projected customer Demand is allowed except:

   - Interruption of Demand that is directly served by the elements that are removed from service as a result of the Contingency
   - Planned or controlled interruption of Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities
   - Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
   - Interruptible Demand or Demand-Side Management

If you feel that your comment has been overlooked, 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, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Comments and Responses from Formal Comment Period:

Comments and Responses from Initial Ballot:

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, 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, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
4.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
5.	Sylvain Clermont	Hydro-Quebec TransEnergie		1
6.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
7.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
8.	Ben Eng	New York Power Authority	NPCC	4
9.	Brian Evans-Mongeon	Utility Services	NPCC	8
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
11.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
12.	Kathleen Goodman	ISO - New England	NPCC	2
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1
14.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
15. Randy MacDonald			New Brunswick System Operator	NPCC					2				
16. Bruce Metruck			New York Power Authority	NPCC					6				
17. Lee Pedowicz			Northeast Power Coordinating Council	NPCC					10				
18. Robert Pellegrini			The United Illuminating Company	NPCC					1				
19. Saurabh Saksena			National Grid	NPCC					1				
20. Michael Schiavone			National Grid	NPCC					1				
2.	Group	Philip R. Kleckley	South Carolina Electric & Gas	X		X		X					
Additional Member			Additional Organization	Region					Segment Selection				
1. Bob Jones			Southern Company Services - Trans.	SERC					1				
2. David Marler			Tennessee Valley Authority	SERC					1				
3. Charles Long			Entergy	SERC					1				
4. James Manning			North Carolina Electric Membership Corporation	SERC					3				
5. Pat Huntley			SERC Reliability Corporation	SERC					10				
3.	Group	John Bee	Exelon Transmission Strategy & Compliance	X		X		X					
Additional Member			Additional Organization	Region					Segment Selection				
1. Mortenson, Eric			:(ComEd)	RFC					1				
2. Weaver, David W			(PECO)	RFC					1				
3. McHugh, Kathleen P			(PECO)	RFC					1				
4. Kay, Thomas W			(ComEd)	RFC					1				
5. Szymczak, Ronald			(ComEd)	RFC					1				
6. Chu, Ron F			(PECO)	RFC					1				
7. Donnelly, Michael J			(PECO)	RFC					1				
8. Kliros, Chris B			(ComEd)	RFC					1				
9. Mills, Paul M			(ComEd)	RFC					1				
10. Webb, Becky			(ComEd)	RFC					1				
4.	Group	Denise Koehn	BPA, Transmission Reliability Program	X		X		X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
	Additional Member		**Additional Organization**	**Region**					**Segment Selection**				
1. Chuck Matthews			BPA, Transmission Planning	WECC					1				
2. Berhanu Tesema			BPA, Transmission Planning	WECC					1				
3. Larry Furumasu			BPA, Transmission Planning	WECC					1				
4. Kyle Kohne			BPA, Transmission Planning	WECC					1				
5. Don Watkins			BPA, Transmission System Operations	WECC					1				
6. Rebecca Berdahl			BPA, Power, Long Term Sales and Purchases	WECC					3				
5.	Group	Carol Gerou	Midwest Reliability Organization										X
	Additional Member		**Additional Organization**	**Region**					**Segment Selection**				
1.	Chuck Lawrence		American Transmission Company	MRO					1				
2.	Tom Webb		Wisconsin Public Service	MRO					3, 4, 5, 6				
3.	Terry Bilke		Midwest ISO Inc.	MRO					2				
4.	Jodi Jenson		Western Area Power Administration	MRO					1, 6				
5.	Ken Goldsmith		Alliant Energy	MRO					4				
6.	Dave Rudolph		Basin Electric Power Cooperative	MRO					1, 3, 5, 6				
7.	Eric Ruskamp		Lincoln Electric System	MRO					1, 3, 5, 6				
8.	Joseph Knight		Great River Energy	MRO					1, 3, 5, 6				
9.	Joe DePoorter		Madison Gas & Electric	MRO					3, 4, 5, 6				
10.	Scott Nickels		Rochester Public Utilities	MRO					4				
11.	Terry Harbour		MidAmerican Energy Company	MRO					1, 3, 5, 6				
6.	Group	Richard Kafka	Pepco Holdings, Inc.	X		X		X	X				
	Additional Member		**Additional Organization**	**Region**					**Segment Selection**				
1. Jim Summers			Delmarva Power and Light Co.	RFC					1				
2. John Radman			Potomac Electric Power Company	RFC					1				
7.	Group	Ben Li	IESO		X								
	Additional Member		**Additional Organization**	**Region**					**Segment Selection**				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1. Bill Phillips			MISO	MRO									
2. James Castle			NYISO	NPCC									
3. Charles Yeung			SPP	SPP									
4. Lourdes Estrada-Salinero			CAISO	WECC									
5. Patrick Brown			PJM	RFC									
6. Steve Myers			ERCOT	ERCOT									
8.	Group	Frank Gaffney	Florida Municipal Power Agency	X			X	X	X				
Additional Member			Additional Organization	Region					Segment Selection				
1. Timothy Beyrle			Utilities Commission of New Smyrna Beach	FRCC					4				
2. Greg Woessner			Kissimmee Utility Authority	FRCC					1				
3. Jim Howard			Lakeland Electric	FRCC					1				
4. Lynne Mila			City of Clewiston	FRCC					3				
5. Joe Stonecipher			Beaches Energy Services	FRCC					1				
6. Cairo Vanegas			Fort Pierce Utility Authority	FRCC					4				
9.	Individual	Stephen Mizelle	Southern Company Transmission	X									
10.	Individual	Robert Casey	Georgia Transmission Corporation (Bulk System Planning)	X									
11.	Individual	Thad Ness	American Electric Power	X		X		X	X				
12.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
13.	Individual	Martin Bauer	US Bureau of Reclamation					X					
14.	Individual	Kirit Shah	Ameren	X		X		X	X				
15.	Individual	Robert W. Roddy	Dairyland Power Cooperative	X		X		X					

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
16.	Individual	Marty Berland	Progress Energy	X		X		X	X				
17.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X					
18.	Individual	Charles Lawrence	American Transmission Company	X									
19.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
20.	Individual	Bill Middaugh	Tri-State Generation and Transmission Association, Inc.	X		X		X	X				
21.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									
22.	Individual	Dan Rochester	Independent Electricity System Operator		X								

1. **The SDT is proposing a revision to footnote 'b' in the TPL tables to comply with FERC Order RM-06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system by June 30, 2010. Do you agree with the proposed changes and if not, please provide specific reasons for your disagreement.**

Summary Consideration: The SDT has listened to the comments from the industry, understands the concerns raised, and has made changes to the footnote to balance the various industry concerns while assuring BES reliability.

The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. This is limited by two conditions: >90% demand level and 50 MW. The >90% demand level was selected to ensure that the number of hours with exposure to demand loss was not unlimited. A 90% demand level is a reasonably stressed case for most systems and the number of hours when peak demands are >90% is a small percentage of the time for most systems. A large percentage of the transmission lines that directly serve distribution customers are 161 kV or lower voltages. Ten percent (10%) of the demand on a high capacity 161 kV transmission line is approximately 50 MW.

A 4th bullet has also been added to clarify that it is acceptable to use Interruptible demand and Demand-Side Management.

To match the terminology in the revised footnote with the terminology in the associated column heading (Loss of Demand or Curtailed Firm Transfers) the term, 'Load' was replaced with 'Demand' and the term 'Firm Transmission Service' was replaced with 'firm transfers.'

Footnote 'b' now reads:

b)~~-~~No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Duke Energy	No	Duke Energy voted "Negative" on the initial and current ballots of TPL-001-1, primarily because Duke believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We also sought rehearing on the Commission's March 18 Order Setting Deadline for Compliance (Docket No. RM06-16), with respect to this and other issues. We believe that FERC's directive in that Order to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the potential impacts (environmental, historical, archaeological, aesthetic...) of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. Duke offers the following ideas on alternatives for the SDT to consider that will allow for appropriate discretion and facilitate proper planning while allowing non-consequential load loss (NCLL).The standard should allow for dropping of limited amounts of non-consequential load in situations where it would be reasonable for a bounded time period and under restricted system conditions (e.g. 1-3 years only when load is >90 % of peak conditions). Dropping of non-consequential load would be prudent planning in situations where the near term impact of load projections or implementation of nearby transmission/generation projects will alleviate the necessity of an upgrade to meet N-1 conditions. Also, reliability of service to end-use customer is impacted by the entire system from source to load. Where allowance for NCLL would not greatly impact individual end-use customers' level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to avoid projects without greatly impacting a customer's outage frequency

Organization	Yes or No	Question 1 Comment
		and duration should be acceptable. Use of reliability metrics (e.g. SAIFI/SAIDI/ASAI) should also be considered by the SDT for determination of acceptable use of NCLL.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. The SDT discussed the use of reliability metrics for providing flexibility to planners but has not included their use as this would make the implementation too complex.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Midwest Reliability Organization	No	For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.
Dairyland Power Cooperative	No	DPC concurs with the MRO comments: For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.
American Transmission Company	No	For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant

Organization	Yes or No	Question 1 Comment
		transmission system modifications.

Response: The SDT has added the fourth bullet to address your concern.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Georgia Transmission Corporation (Bulk System Planning)	No	Georgia Transmission Corporation (GTC) believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We believe that FERC's directive in (Docket No. RM06-16) to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view

Organization	Yes or No	Question 1 Comment
		to allow loss of non-consequential load.We also note that on April 19 NERC filed a request for rehearing with FERC asking that the Commission revise the directive in Paragraph 8 of the March 18 TPL-002 Order to allow NERC the necessary time to incorporate changes to the TPL-002 Reliability Standard through the Reliability Standards Development Process that are necessary to achieve bulk power system reliability. NERC also requested that the Commission grant NERC's Motion for Stay to stay the Order so that a public technical conference with opportunity for comment can be held in order to provide parties an opportunity to meet and discuss the technical considerations of developing a modification to the TPL-002 standard that prohibits the loss of non-consequential firm load in the event of an N-1 contingency. NERC's April 19 filing pointed out that if the Commission's directive to disallow the loss of non-consequential firm load for an N-1 contingency is implemented, a question is presented regarding whether the Reliability Standard still serves the purpose of ensuring the Reliable Operation of the bulk power system by preventing instability, uncontrolled separation, and cascading failures. That is, the Commission's directive sets forth an expectation that NERC is to implement standards that address all loss of load at costs that may not be commensurate with bulk power system reliability, as statutorily defined, which is fundamentally different from what the Reliability Standards were intended to do.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- o Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Progress Energy	No	Progress Energy applauds NERC's efforts to improve the footnote (b) language with respect to conditional allowance of curtailing Firm Transmission Service, which is addressed in the second paragraph of the proposed new footnote (b). PE remains concerned, however, that the first paragraph of the proposed new

Organization	Yes or No	Question 1 Comment
		footnote (b) does not allow for curtailment of non-radial non-consequential load. The ability to curtail non-consequential load in the planning horizon can be a useful tool to mitigate local area issues, and has not been detrimental to the Bulk Electric System (BES). Disallowing the curtailment of non-radial non-consequential load essentially prohibits taking action in situations in which the load in question is clearly at a localized self-contained level of the system, i.e. the distribution system(s) served by the Transmission Owner/Operator. Prohibiting the curtailment of local load thus constitutes regulating distribution feeder reliability rather than BES reliability. Events that could be mitigated through the curtailment of local, non-radial non-consequential load are infrequent, and such curtailment has no material effect on the reliability of the BES. PE therefore suggests that the following addition (item (3)) to the first paragraph of the proposed footnote (b) be considered:"No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, and/or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities, and/or (3) Planned or controlled interruption of any additional Load required to mitigate the post-contingency results, provided that the non-consequential load being shed for the event is localized, and provided that the total load shed for the event does not exceed 2% of the Planned system peak demand or 200 MW, whichever value is less."

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. The SDT did adopt a limit but felt that 2% of system peak or 200 MW was not equitable for all entities.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Hydro-Québec TransEnergie (HQT)	No	The proposed changes do not adequately address FERC's concerns in RM06-16-009. The Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." The proposed changes to footnote 'b' indicate "No interruption of firm Load is allowed except:... (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities." The exception described appears to still allow non-consequential load loss. FERC describes in RM06-16-009 non-consequential load loss as "the removal, by any means, of any firm load that is not directly served by the elements that are removed from service as a result of the contingency." In referencing Order 693, the Commission reiterated its position that TPL standards "should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency." "Must" should be used instead of "should" in the last sentence of the footnote, making it to read "Facility Ratings in those regions must also be respected."
Northeast Power Coordinating Council	No	The proposed changes do not adequately address FERC's concerns in RM06-16-009. The Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." The proposed changes to footnote 'b' indicate "No interruption of firm Load is allowed except:... (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities." The exception described appears to still allow non-consequential load loss. FERC describes in RM06-16-009 non-consequential load loss as "the removal, by any means, of any firm load that is not directly served by the elements that are removed from service as a result of the contingency." In referencing Order 693, the Commission reiterated its position that TPL standards "should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency." "Must" should be used instead of "should" in the last sentence of the footnote, making it to read "Facility Ratings in those regions must also be respected."
Response: The SDT believes that it has been responsive to the FERC directive in that the standards development process has been employed. In the		

Organization	Yes or No	Question 1 Comment
development of the footnote, the SDT has balanced the need for discretion while addressing local area concerns with the need to assure the reliability of the BES. 'Must' is not appropriate in a footnote as it would impose a requirement in the footnote. The SDT has replaced 'should' with 'would' to correct the grammar. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Tri-State Generation and Transmission Association, Inc.	No	Tri-State does believe that the new footnote is an improvement, but thinks there are still some changes necessary. We believe that the word "only" should be removed from the phrase "...where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities" because that discrimination was not required in FERC Order RM-06-16-009. There may be times when facilities near the temporary radial facilities might also fall outside the limits set in reliability criteria but the situation is mitigated if the load shedding occurs at the radial facility. The meaning of the second paragraph of the new footnote is unclear. Tri-State recommends changing it to "Curtailment of Firm Transmission Service is not allowed unless it is coupled with curtailment-offsetting resources that are obligated to re-dispatch. Further, the curtailment activities cannot result in the shedding of any Firm load or in violations of Facility Ratings, either internal or external to the planning region."
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. Instead of removing the word 'only', the 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:		

Organization	Yes or No	Question 1 Comment
		o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Southern Company Transmission	No	We propose that the section in double parentheses be deleted. The proposed wording by the drafting team seems to imply that the curtailment of firm transmission service is permitted to address single contingency constraints if coupled with the redispatch of network resources. The original language stated only that curtailments were permitted to prepare for the next contingency, not to address loading related to the initial contingency. The proposed wording could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint. Southern Companies recommend that the original language relating to "preparing for the next contingency" be incorporated into the drafting team's proposal.((Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.)) No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch. where it can It must be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

Organization	Yes or No	Question 1 Comment

Response: The SDT believes that System re-dispatch is an acceptable System adjustment to "remain within applicable Facility Ratings" to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can be only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the Firm Transmission Service cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- o Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
South Carolina Electric & Gas	Yes	For better clarity delete the phrase "when coupled with" in the second paragraph of footnote 'b.'

Response: The SDT did not delete the suggested phrase as it believes it is correct as stated but added commas to make the phrase read more clearly.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~

Organization	Yes or No	Question 1 Comment
o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Independent Electricity System Operator	Yes	IESO supports the revisions made to footnote 'b' based on the present definitions of BES and Firm Demand and on the understanding that the NERC standards apply only to the BES as defined in the NERC Glossary as follows:"As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition." To be clear, our interpretation of the present definition of BES is that it defers to each Regional Reliability Organization to define the elements of the power system that are considered BES and, therefore in the NPCC Region, "BES as defined by NERC" = "BPS as defined by NPCC".
Response: The SDT agrees that the standard applies to the BES as defined in the Glossary.		
BPA, Transmission Reliability Program	Yes	On the firm transfer issues, the term "Firm Transmission Service" should be replaced with "Firm Transfers" to be consistent with the fourth column of the existing Table 1 Transmission System Standards - Normal and Emergency Conditions.
Response: The SDT agrees and has made the change. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW		

Organization	Yes or No	Question 1 Comment
o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
American Electric Power	Yes	
Exelon Transmission Strategy & Compliance	Yes	
Florida Municipal Power Agency	Yes	
IESO	Yes	
Northeast Utilities	Yes	
Pepco Holdings, Inc.	Yes	
US Bureau of Reclamation	Yes	
Manitoba Hydro	Yes	MH agrees with the SDT proposal.
Ameren	Yes	We were ok with the previous language. Though we do not intend to drop non-consequential load for a single contingency, we undersatnd that other ares may have been following such practice without degarding the relaibility of BES. We believe that they can continue this practice if they develop non-firm contracts with these customers.
Response: Thank you for your support.		

2. Are you aware of any conflicts caused by compliance with the proposed language in Table 1 — footnote b and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement? If yes, please identify the conflict.

Summary Consideration: The SDT understands that there may be conflicts as pointed out by respondents; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.

b)~~–~~No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 2 Comment
Ameren	No	
American Electric Power	No	
American Transmission Company	No	
BPA, Transmission Reliability	No	

Organization	Yes or No	Question 2 Comment
Program		
Dairyland Power Cooperative	No	
Exelon Transmission Strategy & Compliance	No	
Independent Electricity System Operator	No	
Manitoba Hydro	No	
Midwest Reliability Organization	No	
Southern Company Transmission	No	
US Bureau of Reclamation	No	
South Carolina Electric & Gas	No	The comments expressed herein represent a consensus of the views of the above named members of the SERC Engineering Committee Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.
Response: Thank you for your response.		
Hydro-Québec TransEnergie (HQT)	Yes	Conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.
Northeast Power Coordinating Council	Yes	Conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.

Organization	Yes or No	Question 2 Comment
IESO	Yes	It should be noted that conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. In RM-06-16-009, the Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." In the US, State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.Similar conflicts may also exist in Canada.
Progress Energy	Yes	There is the potential for conflict between Table 1 - Footnote (b) as currently proposed, which can be considered to regulate local distribution reliability without improving BES reliability, and local service reliability issues which are under the purview of state regulatory agencies. For example, the North Carolina Utilities Commission (NCUC) commented regarding this concern in the ballot which ended March 1 in Project 2006-02. Specifically, NCUC commented that they were "...concerned that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1 is an inappropriate overreach into service issues that are more appropriately addressed by state regulatory commissions..." Progress Energy believes that NCUC's concerns are legitimate. BES reliability should address the avoidance and mitigation of cascading outages and BES facility damage, rather than limited, controlled local area loss of load, in order to avoid this conflict and overlap of regulation.
Response: The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.		
Northeast Utilities	Yes	Northeast Utilities (NU) believes the language of the proposed revision to footnote 'b' can be better defined as the proposed revision is subject to interpretation by the different entities and regulatory agencies. Future conflicts can be minimized by further clarifying the proposed revision. Also, NU is concerned that this new modification does not specify the amount of permissible load shed nor does it require the planning entity to minimize load shedding under this exception.
Response: The SDT has made several clarifying changes to the footnote which should alleviate your concerns. The SDT has modified the footnote for clarity and added constraints in new bullet 3 to address your specific concern.		

Organization	Yes or No	Question 2 Comment
b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Duke Energy	Yes	See response to question #1.
Georgia Transmission Corporation (Bulk System Planning)	Yes	See response to Question #1.
Response: See response to question #1.		
Florida Municipal Power Agency	Yes	This is an area of fuzziness between State jurisdiction and Federal jurisdiction. In all honesty, shedding load for local area impacts has nothing to do with BES reliability and should not be under FERC jurisdiction under Section 215 of the Federal Power Act, but rather State jurisdiction for quality of service issues. However, there is also the matter of FERC jurisdiction over commercial matters and the opportunity to "game" the original footnote by transmission providers by allowing firm load shedding to grant firm transmission service for themselves, thereby avoiding or deferring transmission investment, while at the same time denying or requiring others to build the same transmission avoided in order to obtain transmission service. We can see how difficult it is from a drafting team's perspective in achieving a balanced position between these different matters. The drafting team should be applauded for finding a reasonable position.
Pepco Holdings, Inc.	Yes	This is not an issue for historic PJM members, but as PJM has expanded and as a result of the merger of historic councils into RFC, I am aware that not all regions had standards equal to those of MAAC, and this

Organization	Yes or No	Question 2 Comment
		has been an issue worked out between transmission planners (historic transmission owners) and their local regulators. It is ultimately a cost issue for loss of local load that does not affect the overall reliability of the interconnected BES.
Response: Thank you for your support.		
Tri-State Generation and Transmission Association, Inc.	Yes	We believe that FERC's directive in FERC Order RM-06-16-009 to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load.
Response: The SDT is not in a position to comment on FERC's authority. The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.		

3. Consideration of Comments on Initial Ballot — TPL Table 1 Order (Project 2010-11) May 17–27, 2010

Summary Consideration: The SDT has listened to the comments from the industry, understands the concerns raised, and has made changes to the footnote to balance the various industry concerns while assuring BES reliability.

The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. This is limited by two conditions: >90% demand level and 50 MW. The >90% demand level was selected to ensure that the number of hours with exposure to demand loss was not unlimited. A 90% demand level is a reasonably stressed case for most systems and the number of hours when peak demands are >90% is a small percentage of the time for most systems. A large percentage of the transmission lines that directly serve distribution customers are 161 kV or lower voltages. Ten percent (10%) of the demand on a high capacity 161 kV transmission line is approximately 50 MW.

A 4th bullet has also been added to clarify that it is acceptable to use Interruptible demand and Demand-Side Management.

The second paragraph of the footnote has been clarified and references Firm Transfers now instead of Firm Transmission Service.

b)~~-~~No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- o Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Rodney Phillips	Allegheny Power	1	Negative	Allegheny Power believes the loss of non-consequential load and/or curtailment of transmission service for N-1 contingencies should be limited to only extreme circumstances. Exception 2 of footnote b allows for the loss of non-consequential load for N-1

Voter	Entity	Segment	Vote	Comment
				contingencies with no restriction. Allegheny Power recommends removing exception 2 footnote b.
Response: The SDT and the majority of the commenters disagree with this suggestion.				
Gordon Rawlings	BC Transmission Corporation	1	Negative	BCTC appreciates the good work of the SAR committee in drafting the changes to Footnote b of Table 1. BCTC agrees with the drafting team that interruption of firm load, served by either radial circuits or circuits that have became radial as a result of the contingency, should be allowed for N-1 contingencies. However, it is our position that interruption of firm load should not be limited only to such consequential loads. In our view, interruption of electric supply to some local network customers in the affected area should be permissible. This inclusion will allow transmission planners to plan BCTC's regional transmission network reliably and without impacting neighbouring transmission networks.
Faramarz Amjadi	BC Transmission Corporation	2	Negative	
Hubert C. Young	South Carolina Electric & Gas Co.	3	Negative	SCE&G has significant concern with the proposed revision to TPL Table 1, Footnote B. The current Footnote B states "Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems". The phrase "without impacting the overall reliability of the interconnected transmission systems" is important to the TPL standards to ensure that ERO standards do not dictate the level of service to customers. Service to customers and load pockets is jurisdictional to State Commissions and ERO standards should not compromise this jurisdiction. SCE&G believes that any proposed revisions to Footnote B must retain the concept that planned or controlled interruption of electric supply to customers, whether they are radial or network, is allowed as long as it does not impact the overall reliability of the interconnected transmission systems. The proposed revision eliminates this concept. There seems to be a general inconsistency and maybe confusion between the terms "reliability" and "level of service".
David Frank Ronk	Consumers Energy	4	Negative	The current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the previous version of TPL-001-1. However, it still does not allow Transmission Planners to use appropriate and necessary discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should control the decision making when BES reliability is not an issue. Often, the consequences of these events are solely local in nature, requiring only minor additional loss of local load to
James B Lewis	Consumers Energy	5	Negative	

Voter	Entity	Segment	Vote	Comment
				avoid the costly major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load.
Hugh A. Owen	Public Utility District No. 1 of Chelan County	6	Negative	The interruption of a small amount of load is, under most conditions, not a risk to the reliability of the BES and is at times necessary to preserve reliability. The planned interruption of some load may be a cost effective alternative to a costly transmission project. That is a quality of service issue.
Michael Gammon	Kansas City Power & Light Co.	1	Negative	While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load.
Charles Locke	Kansas City Power & Light Co.	3	Negative	
Thomas Saitta	Kansas City Power & Light Co.	6	Negative	
Linda Brown	San Diego Gas & Electric	1	Affirmative	As to item (1), all load served directly by a transmission element which experiences a fault will be interrupted when the faulted element is taken out of service. This is the natural relationship between the load and the transmission element. Allowing this for BES elements may encourage transmission owners to remove transmission instead of upgrading or replacing it. Consider a load supplied by two transmission lines of different capacity. If the larger line is lost due to a contingency (N-1) and the remaining smaller line overloads the transmission owner is left with several options to address the problem: (1) move load between buses, (2) upgrade the smaller line, (3) add another line, or (4) create a radial load by removing the smaller line. Number (4) may be the least expensive and allowable under TPL-002, footnote b. Item (2) may also encourage transmission owners to develop plans which make load shedding part of category B. Consider a load served by three transmission lines, a utility may decide to remove a line, instead of upgrading, in order to set up a situation where an N-1 contingency would make the bus temporarily radial. In the event of a single outage (N-1), the load bus will be temporarily radial and load can be shed at the bus.

Voter	Entity	Segment	Vote	Comment
W. R. Schoneck	Florida Power & Light Co.	3	Affirmative	I believe the language is an improvement and clarifies the intent but I believe there still should be additional language added to give an exemption in meeting this requirement if it does not make economic sense(not economically feasible) and has no real impact on the BES.
Richard J Kafka	Potomac Electric Power Co.	1	Affirmative	It is understood that this is a compliance filing issue. This is not an issue for historic PJM members, but as PJM has expanded and as a result of the merger of historic councils into RFC, I am aware that not all regions had standards equal to those of MAAC, and this has been an issue worked out between transmission planners (historic transmission owners) and their local regulators. It is ultimately a cost issue for loss of local load that does not affect the overall reliability of the interconnected BES.
Alan Gale	City of Tallahassee	5	Affirmative	TAL thanks for SDT for the tireless effort to get to this point. TAL is voting affirmative with the following comments. We accept that the loss of non-consequential load is not a desired result for N-1 contingencies. It is also not the norm in system planning or operations. The flexibility to operate the system consistent with “good utility practice” may warrant the “odd-ball” case that would require this to occur. The dropping of non-consequential load will NOT lead to BES instability, voltage collapse, or cascading outages, which is what FERC and NERC are charged with preventing. It will lead to the shedding of load in a local area only. Utilities do not drop customers lightly. If the meter isn’t turning, we are not getting paid, so we want the meter spinning. Utility power, while vital to our normal day-to-day lives and infrastructure, was never intended to be without interruption.
Brad Chase	Orlando Utilities Commission	1	Affirmative	This change raises the bar on transmission system performance. This change applies a blanket requirement upon entities that does not take into account the number of outages, probability of outages or cost to the customer. There are certain to be situations where this blanket requirement will result in increased cost to customers for no noticeable increase in reliability. OUC does agree with the concept of greater clarification on this requirement, however this clarification may raise the bar to far by trying to establish a blanket requirement. Duke, Progress Energy and others will be submitting comments with proposed language that attempt to address some of these issues and we encourage the drafting team to consider those comments.
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate				

Voter	Entity	Segment	Vote	Comment
constraints. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.				
Eric Egge	Black Hills Corp	1	Negative	Black Hills believes that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.

Voter	Entity	Segment	Vote	Comment
Chifong L. Thomas	Pacific Gas and Electric Company	1	Negative	PG&E commends the SDT for developing the proposed footnote b. While it is a great improvement over the complete prohibition on loss of non-consequential load for any single contingency, the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system, especially where the impact is local in nature, to avoid instability, cascading or uncontrolled separation. Such planned interruption of load may be a reasonable alternative to the environmental impacts or prohibitive costs associated with a major new transmission project. Given the potential impacts of the proposed modification, further vetting of the issues is needed. PG&E believes that NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
Thomas J. Bradish	RRI Energy	5	Negative	RRI supports the WECC position on this issue; namely, that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
Trent Carlson	RRI Energy	6	Negative	

Voter	Entity	Segment	Vote	Comment
John Tolo	Tucson Electric Power Co.	1	Negative	The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project.
James Tucker	Deseret Power	1	Negative	The prohibition of loss of non-consequential load for events resulting the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
Louise McCarren	Western Electricity Coordinating Council	10	Negative	The proposed revisions to footnote b of Table 1 are an improvement to the recently balloted prohibition on loss of non-consequential load for single contingencies. The recognition of the new term "temporarily radial" is a step in the right direction. However, the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their

Voter	Entity	Segment	Vote	Comment
				individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
William Mitchell Chamberlain	California Energy Commission	9	Negative	While the proposed revisions to footnote b are an improvement to the prohibition on loss of non-consequential load for a single contingency proposed in the recently failed TPL-001-1 ballot, the prohibition of loss of non-consequential load for events resulting the loss of a single element still inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
John Mick	Colorado Springs Utilities	6	Negative	Colorado Springs Utilities ballot on the proposed changes to TPL Table 1, footnote b directed in FERC Order RM06-16-009 Colorado Springs Utilities wishes to vote NO on the proposed changes to TPL Table 1, footnote b, directed in FERC Order RM06-16-009. CSU concurs with the WECC position paper for the ballot, and agrees with the WECC statement "that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues".
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.				

Voter	Entity	Segment	Vote	Comment

The SDT agrees that a technical conference on this issue would be of value.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- o Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Horace Stephen Williamson	Southern Company Services, Inc.	1	Negative	Comments have already been submitted previously, but it will be added here again. Proposed footnote should read... No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers when coupled with the appropriate re-dispatch of resources obligated to re-dispatch. It must be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. The proposed changes are based on the
Richard J. Mandes	Alabama Power Company	3	Negative	
Anthony L Wilson	Georgia Power Company	3	Negative	

Voter	Entity	Segment	Vote	Comment
Gwen S Frazier	Gulf Power Company	3	Negative	following… "The proposed wording by the drafting team seems to imply that the curtailment of firm transmission service is permitted to address single contingency constraints if coupled with the redispatch of network resources. The original language stated only that curtailments were permitted to prepare for the next contingency, not to address loading related to the initial contingency. The proposed wording could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint. Southern Companies recommend that the original language relating to "preparing for the next contingency" be incorporated into the drafting team's proposal."
Don Horsley	Mississippi Power	3	Negative	
Michael Ibold	Xcel Energy, Inc.	3	Negative	The proposed modification to footnote b of Table I in TPL-001 - 004 standards states that after a Category B contingency, there should not be any thermal, voltage or stability violation, no interruption of firm load (except the load that is directly connected to the elements that are removed from service as a result of the contingency) and no firm transfer curtailment (except when coupled with re-dispatch of resources obligated to re-dispatch). We believe the proposed footnote b creates a gap between TPL-002 and TPL-003 standards, since it does not address conditions when firm load shedding and firm transfer curtailments are not required to meet the system performance for Category B contingency, but one or both are the required system adjustments to prepare for the next contingency (Category C3). When firm transfer is curtailed after the first contingency in preparation for the next contingency, it is not clear from the proposed footnote b if this is considered a valid system adjustment for Category C or a violation of Category B. Recall that the existing footnote b addresses this condition explicitly by stating "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm Transfers."
Liam Noailles	Xcel Energy, Inc.	5	Negative	
David F. Lemmons	Xcel Energy, Inc.	6	Negative	
George T. Ballew	Tennessee Valley Authority	5	Affirmative	TVA appreciates the work of the SDT on this issue. However, TVA recommends revising the second paragraph of the revised footnote b: "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. However, curtailment of Firm Transmission Service is only allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility
Marjorie S. Parsons	Tennessee Valley Authority	6	Affirmative	

Voter	Entity	Segment	Vote	Comment
				Ratings in those regions should also be respected." Without the changes in the first two sentences above, the proposed wording by the SDT could be interpreted to allow re-dispatch/firm curtailments to address any single contingency constraint instead of in preparation for the next contingency.
Larry Akens	Tennessee Valley Authority	1	Affirmative	TVA appreciates the work of the SDT. However, TVA recommends revising the second paragraph of the revised footnote "b". Without changes in the first two sentences, the proposed wording by the SDT could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint instead of in preparation for the next contingency.

Response: The SDT believes that System re-dispatch is an acceptable System adjustment to "remain within applicable Facility Ratings" to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can be only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the Firm Transmission Service cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Robert W. Roddy	Dairyland Power Coop.	1	Negative	DPC CONCURS WITH THE MRO COMMENTS.
Jason Shaver	American Transmission Company, LLC	1	Affirmative	For Footnote b, add a third exception to the list, “or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed if the tripping of the load is either accepted or volunteered by the customer.
Lawrence R. Larson	Otter Tail Power Company	1	Negative	The change precludes the use of direct load control systems that should be allowed to relieve transmission problems. These systems control firm transmission load but rate conditions can allow their use to mitigate transmission problems.

Response: *(Note - MRO did not submit comments with the initial ballot – but did submit the following comment during the formal comment period: For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.)*

The SDT has added the fourth bullet to address your concern.

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- o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- o Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Ajay Garg	Hydro One Networks, Inc.	1	Negative	Hydro One is casting a negative vote for the following reasons: 1. The amendment to the footnote does not add any technical value to the standard. It was added only to satisfy a FERC directive to address comments made to allow non-consequential load loss after a single contingency event, "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." 2. Addressing curtailment of Firm Transmission Service with re-dispatch of resources is a matter of a commercial nature and should be dealt with in the agreements dealing with such services. Issues of contracted transmission services, firm or otherwise, are not a reliability related matter and are not to be dealt with in this standard. 3. Matters of interruption of firm load should be incorporated into this standard only after the FERC NOPR on the definition of the BES is resolved. As it stands, the footnote will pose significant problems if the 100 kV and above FERC proposal is applied across the board, unless the standard specifically states that it applies to the BES as defined by the region (current definition).
Michael D. Penstone	Hydro One Networks, Inc.	3	Negative	
Response: 1. & 2. The SDT disagrees – there is a direct impact on reliability of the BES associated with these concerns. The SDT has added clarity to the footnote by designating constraints for Demand and firm transfer curtailment. 3. The SDT disagrees that this needs to wait on the FERC NOPR. This standard is applicable to the BES as it is defined.				
Spencer Tacke	Modesto Irrigation District	4	Negative	I am voting NO vote because of the lack of clarity of the second paragraph of the proposed change. Although paragraph 1 is an improvement to the current wording, and actually allows for some specific flexibility in shedding load for an N-1 event, the lack of clarity in the second paragraph could lead to varied interpretations by members and compliance auditors. Thank you.
Response: The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:				

Voter	Entity	Segment	Vote	Comment
				o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Dana Cabbell	Southern California Edison Co.	1	Negative	It is SCE's position that the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. When planned load interruption is identified as a response to a single event, the impact to the system is often local in nature. The planned interruption of load may be a desirable alternative to the prohibitive costs associated with a major new transmission project. If the NERC Standards Drafting Team decides to proceed with footnote B, as written, it needs to ensure that Transmission Owners, Transmission Operators, and Transmission Planners have enough time to both design and implement any mitigation plans necessary to be compliant with the new language. In almost all cases the actual implementation of a solution requiring new construction will be dependent on a number of different regulatory agencies providing the necessary permits allowing for its construction. As such, NERC needs to ensure that any time frame associated with compliance to the proposed language be variable, and allow for extended implementation time frames based on system conditions that may delay placing mitigation plans in service. An example of a reasonable variable time frame to be compliant with the proposed language in footnote B would be to start the clock 60 months from receiving the pertinent environmental permitting. In
David Schiada	Southern California Edison Co.	3	Negative	
Ahmad Sanati	South California Edison Company	5	Negative	

Voter	Entity	Segment	Vote	Comment
				California this could be the issuance of a Draft Environmental Impact Review pursuant to the California Environmental Quality Act.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

The SDT has added more latitude for the Transmission Planner with the addition of the 3rd bullet and believes that 60 months should be sufficient.

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- o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- o Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Henry Ernst-Jr	Duke Energy Carolina	3	Negative	On the initial ballot of TPL-001-1 Duke Energy also voted "Negative", primarily because Duke believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We also sought rehearing on the Commission's March 18 Order Setting Deadline for Compliance (Docket No. RM06-16), with respect to this and other issues. We believe that FERC's directive in that Order to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the potential impacts (environmental, historical, archaeological, aesthetic...) of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. With this "Negative" vote, Duke offers the following ideas on alternatives for the SDT to consider that will allow for appropriate discretion and facilitate proper planning while allowing non-consequential load loss (NCLL). The standard should allow for dropping of limited amounts of non-consequential load in situations where it would be reasonable for a bounded time period and under restricted system conditions (e.g. 1-3 years only when load is >90 % of peak conditions). Dropping of non-consequential load would be prudent planning in situations where the near term impact of load projections or implementation of nearby transmission/generation projects will alleviate the necessity of an upgrade to meet N-1 conditions. Also, reliability of service to end-use customer is impacted by the entire system

Voter	Entity	Segment	Vote	Comment
				from source to load. Where allowance for NCLL would not greatly impact individual end-use customers' level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to avoid projects without greatly impacting a customer's outage frequency and duration should be acceptable. Use of reliability metrics (e.g. SAIFI/SAIDI/ASAI) should also be considered by the SDT for determination of acceptable use of NCLL.
Luther E. Fair	Gainesville Regional Utilities	1	Affirmative	Even though I am voting in the affirmative, I agree that most of the comments offered by Duke and Norther Indiana in their earlier statements have merit and should be considered. Also, I believe that the use of reliability metrics should be considered by the SDT for determination of acceptable use of NCLL.
Mace Hunter	Lakeland Electric	3	Negative	Reliability should consider the entire system from source to load. Where allowance for NCLL would not greatly impact individual end-use customer's level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to delay projects without greatly impacting a customer's outage frequency and duration should be acceptable. Use of reliability metrics should also be considered by the SDT for determination of acceptable use of NCLL.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

The SDT discussed the use of reliability metrics for providing flexibility to planners but has not included their use as this would make the implementation too complex.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

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				o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Sammy Roberts	Progress Energy Carolinas	1	Negative	Progress Energy applauds NERC's efforts to improve the footnote (b) language with respect to conditional allowance of curtailing Firm Transmission Service, which is addressed in the second paragraph of the proposed new footnote (b). PE remains concerned, however, that the first paragraph of the proposed new footnote (b) does not allow for curtailment of non-radial non-consequential load. The ability to curtail non-consequential load in the planning horizon can be a useful tool to mitigate local area issues, and has not been detrimental to the Bulk Electric System (BES). Disallowing the curtailment of non-radial non-consequential load essentially prohibits taking action in situations in which the load in question is clearly at a localized self-contained level of the system, i.e. the distribution system(s) served by the Transmission Owner. Prohibiting the curtailment of local load thus constitutes regulating distribution feeder reliability rather than BES reliability. Events that could be mitigated through the curtailment of local, non-radial non-consequential load are infrequent, and such curtailment has no material effect on the reliability of the BES. PE therefore suggests that the following addition (item (3)) to the first paragraph of the proposed footnote (b) be considered: "No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, and/or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities, and/or (3) Planned or controlled interruption of any additional Load required to mitigate the post-contingency results, provided that the non-
Lee Schuster	Florida Power Corporation	3	Negative	
Sam Waters	Progress Energy Carolinas	3	Negative	
Wayne	Progress Energy	5	Negative	

Voter	Entity	Segment	Vote	Comment
Lewis	Carolinas			consequential load being shed for the event is localized, and provided that the total load shed for the event does not exceed 2% of the Planned system peak demand or 200 MW, whichever value is less.”

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. The SDT did adopt a limit but felt that 2% of system peak or 200 MW was not equitable for all entities.

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- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Timothy VanBlaricom	California ISO	2	Negative	The California ISO supports NERC's request for a public technical conference to be held, as described in NERC's April 19, 2010 request for rehearing and motion for stay of the March 18 Order (RM06-16-009), to provide the opportunity to gain industry input and written comments regarding the Commission's TPL-002-0 directive for NERC to develop a modification to the TPL-002-0 Table 1 footnote b.

Response: The SDT agrees that a technical conference would be of value.

Voter	Entity	Segment	Vote	Comment
Terry L. Blackwell	Santee Cooper	1	Negative	The Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning processes appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. Table B footnote still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, and local customers should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. The Commission's directive sets forth an expectation that NERC is to implement standards that address all loss of load at costs that may not be commensurate with bulk power system reliability, as statutorily defined, which is fundamentally different from what the Reliability Standards were intended to do.
Zack Dusenbury	Santee Cooper	3	Negative	
Suzanne Ritter	Santee Cooper	6	Negative	
Response: The SDT is not in position to comment on FERC's authority. The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.				
Kimberly J. Jones	North Carolina Utilities Commission	9	Negative	The NC Utilities Commission is concerned that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1, and as explained in draft footnote b, is an inappropriate overreach into service issues that are more appropriately addressed by state regulatory commissions. This requirement does not provide any benefit to reliability of the bulk electric system and could undermine state efforts to balance reliability issues with cost of service issues. The standard should continue to allow Transmission Planners to use discretion regarding loss of non-consequential load, understanding that state commissions are positioned to force electric utilities to address local service quality issues on an expedited basis, should it be necessary and in the public interest.
Response: The SDT understands the concern but believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.				

Voter	Entity	Segment	Vote	Comment
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Negative	THE PROPOSED INTERPRETATION WILL UNDERMINE THE INTERNATIONAL STANDARDS SETTING PROCESS AND COULD RESULT IN DIFFERING INTERPRETATIONS OF STANDARDS ON THE NORTH AMERICAN BULK-POWER SYSTEM.
Response: The SDT disagrees and believes that the footnote has been clarified appropriately within the standards development process.				
Daryn Barker	Louisville Gas and Electric Co.	6	Negative	The revised footnote b on Table 1 imposes additional requirements on the responsible entities. The footnote states: Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. However, R1 states: The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned These statements address different and inconsistent scope. If the change in scope was intended then a change should also be made to R1 to reconcile the inconsistency.
Charlie Martin	Louisville Gas and Electric Co.	5	Negative	Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. However, R1 states: The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned These statements address different and inconsistent scope. If the change in scope was intended then a change should also be made to R1 to reconcile the inconsistency.
Response: The SDT agrees that your assessment is for your portion of the interconnected grid. However, when performance in one system is dependent on generation dispatch in another system or vice versa, the SDT believes that one must ensure that the re-dispatch is feasible. The SDT does not believe that this presents a conflict with Requirement R1.				
John Apperson	PacifiCorp	3	Negative	This proposal warrants a "no" vote due to the current uncertainty regarding the outcome of the FERC TPL-002 NOPR issued by FERC on March 18, 2010. The impacts of the proposed changes to footnote B cannot be assessed separately from the alternative interpretation of TPL-002 proposed by FERC. The proper planning of a transmission system requires that all performance requirements are known and understood. If only some of the requirements are known and understood it is impossible to properly plan, study, assess, and operate the transmission system.

Voter	Entity	Segment	Vote	Comment
Response: The current TPL-002 is in force and will remain so until the completion of the cited FERC NOPR. This limited scope revision to footnote 'b' is to add clarity to what is in effect.				
Keith V. Carman	Tri-State G & T Association Inc.	1	Negative	Tri-State does believe that the new footnote is an improvement, but thinks there are still some changes necessary. We believe that the word "only" should be removed from the phrase "...where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities" because that discrimination was not required in FERC Order RM-06-16-009. There may be times when facilities near the temporary radial facilities might fall outside the limits set in reliability criteria but the situation is mitigated if the load shedding occurs at the radial facility. The meaning of the second paragraph of the new footnote is unclear. Tri-State recommends changing it to "Curtailment of Firm Transmission Service is not allowed unless it is coupled with curtailment-offsetting resources that are obligated to re-dispatch. Further, the curtailment activities cannot result in the shedding of any Firm load or in violations of Facility Ratings, either internal or external to the planning region." We believe that FERC's directive in FERC Order RM-06-16-009 to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load.
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. Instead of removing the word 'only', the 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.				

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The SDT is not in position to comment on FERC's authority. The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.</td></tr>
<tr><td>Claudiu Cadar</td><td>GDS Associates, Inc.</td><td>1</td><td>Negative</td><td>We do not agree with the proposed changes due to several reasons. Although the proposed change will directly influence the reliability standards and transmission system performances, will also have an indirect impact on the economic side with respect to the expansion of existing transmission system. We believe that FERC directive as stipulated in Order 693 cannot constrict, nor impose certain actions outside of the reliability limits. We believe that since these events are merely isolated and rarely enforced, the decision of mandating a great financial effort as a consequence of the proposed changes would certainly be counterbalanced by its feasibility when compare with the current cost of load shedding. While the revised footnote b can be certainly considered an improvement from the current version, however it still does not allow the joined entities involved to have power over the decision making when BES reliability is not an issue.

We also believe that any mandatory changes implemented in the TPL standards under the current scenario are not entirely feasible unless all other issues such as the definition of the</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
				BES, Consequential / Non-consequential Load, BES Critical Element, etc gets resolve ahead. The revision with respect to load shedding, specifically the portion about shedding loads on newly radial facilities, does not match the version 1 TPL standard definition of consequential load loss. To approve the proposed revision to footnote 'b' would create an unnecessary discrepancy between the version 1 TPL standard under consideration and the existing standards. We recognize that the Version 1 will replace Version 0, but since it appears that the performance standard with respect to footnote 'b' is intended to be same in the revised footnote and the Version 1 standard, it only makes sense that the revised version 0 footnote 'b' match the consequential load loss definition contemplated in Version 1. In the light of the above we suggest the Commission to approach different other solutions and ideas for improving the current reliability of the transmission system without enforcing decisions beyond its statutory scope. We advance an alternative to this matter meant to balance the reliability of the transmission system and its indirect financial impact. Although the solution that we offer would require an extended time for development and implementation, however we urge NERC to consider it in its further approach. Our alternative consists mainly in implementing an additional term such as "Critical Load" which we have briefly figured that would consist in particular load necessary to be maintained in service without interruption. Even though this new term would seemed to be at first related with the quality of the service, however a joint association of transmission planners, customers, regulatory entities as decision makers can simply individualize the load that cannot be shed, as well as future transmission improvements that will be required to serve this envisioned small amount of load rather than the entire load. In this way we will create a reasonable balance in between the reliability of the transmission system and the cost to maintain / improve this reliability.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

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Voter	Entity	Segment	Vote	Comment
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Ronald D. Schellberg	Idaho Power Company	1	Negative	While the proposed revisions are an improvement to the prohibition on loss of non-consequential load for a single contingency proposed in the recently failed TPL-001-1 ballot, that the prohibition of loss of non-consequential load for events resulting the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. However, the removal of: "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers." will require significant adjustments in either TRM or TTC reductions to be compliant with this revised standard in the WECC Region. To construct additional transmission facilities to maintain present day business could easily exceed 10 Billion dollars throughout the WECC region. For example, the Pacific AC Intertie currently has a TTC of 4800 MW spread across 3 500 kV transmission lines. With the loss of one Transmission line, the Pacific AC intertie drops to 3200 MW. Removal of this sentence would require TP either to drop the Firm TTC of the Intertie to 3200, or include a TRM reservation of at least 1600 MW. The TPs would not be able to say that a loss of 1600 MW of import capacity would not result in curtailments of firm load. Just about all multi

Voter	Entity	Segment	Vote	Comment
				transmission line paths in the WECC Region would suffer. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. In the case of long interties between subregions of WECC, these interties have never been planned to operate in this manner. Idaho Power recommends that the sentence permiting system adjustments be reinserted into Footnote B.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

The SDT believes that System re-dispatch is an acceptable System adjustment to “remain within applicable Facility Ratings” to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote ‘b’ clarifies that re-dispatch is allowable to “remain within” ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can be only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the Firm Transmission Service cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words “To prepare for the next Contingency” to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

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<tr><td>Francis J. Halpin</td><td>Bonneville Power Administration</td><td>5</td><td>Affirmative</td><td>For consistency, regarding the firm transfer issue, the term "Firm Transmission Service" should be replaced with "Firm Transfers" in order to be consistent with the fourth column of the existing Table 1 "Transmission System Standards - Normal and Emergency Conditions".</td></tr>
<tr><td colspan="5">Response: The SDT agrees and has made the change.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

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<tr><td>Kim Warren</td><td>Independent Electricity System Operator</td><td>2</td><td>Affirmative</td><td>IESO supports the revisions made to footnote 'b' based on the present definitions of BES and Firm Demand and on the understanding that the NERC standards apply only to the BES as defined in the NERC Glossary as follows: "As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighbouring systems, and associated equipment, generally operated at voltages of 100 kV</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
				or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition." To be clear, our interpretation of the present definition of BES is that it defers to each Regional Reliability Organization to define the elements of the power system that are considered BES and, therefore in the NPCC Region, "BES as defined by NERC" = "BPS as defined by NPCC".
Response: The SDT agrees that the standard applies to the BES as defined in the Glossary.				
Jacquie Smith	ReliabilityFirst Corporation	10	Affirmative	If this revision is an urgent action, then the implementation timeframe should be shorter. In the clarification paragraph below, I do not understand the first sentence. Are there commas missing? What is the requirement and what is the exception? Also, I question the validity of using "should" in the second sentence. If it is a requirement, then it needs to be stated as a requirement. If it is a suggestion, then it does not belong in the standard. No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.
Response: This has not been classified as an 'urgent action'. Commas have been added as appropriate and a re-wording was made which should make this clear. 'Should' has been replaced by 'would' to provide additional clarity. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels				

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				greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
David H. Boguslawski	Northeast Utilities	1	Affirmative	Northeast Utilities (NU) believes the language of the proposed revision to footnote 'b' can be better defined as the proposed revision is subject to interpretation by the different entities and regulatory agencies. Future conflicts can be minimized by further clarifying the proposed revision. Also, NU is concerned that this new modification does not specify the amount of permissible load shed nor does it require the planning entity to minimize load shedding under this exception.

Response: The SDT has made several clarifying changes to the footnote which should alleviate your concerns.

The SDT has modified the footnote for clarity and added constraints in new bullet 3 to address your specific concern.

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Voter	Entity	Segment	Vote	Comment
Donald S. Watkins	Bonneville Power Administration	1	Affirmative	On the firm transfer issues, the term "Firm Transmission Service" should be replaced with "Firm Transfers" to be consistent with the fourth column of the existing Table 1 Transmission System Standards - Normal and Emergency Conditions.
Rebecca Berdahl	Bonneville Power Administration	3	Affirmative	
Brenda S. Anderson	Bonneville Power Administration	6	Affirmative	

Response: The SDT agrees and has made this change.

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Voter	Entity	Segment	Vote	Comment
Frank Gaffney	Florida Municipal Power Agency	4	Affirmative	Please see FMPA comments submitted through the concurrent comment period for Project 2010-11
David Schumann	Florida Municipal Power Agency	5	Affirmative	

Voter	Entity	Segment	Vote	Comment
Response: Please see the response to FMPA comments above.				
Carter B Edge	SERC Reliability Corporation	10	Affirmative	The footnote makes clearer when load can be dropped for planning purposes. By making this footnote more specific, it supports reliability and helps stakeholders apply the TPL standards.
Timothy Beyrle	City of New Smyrna Beach Utilities Commission	4	Affirmative	This is an area of fuzziness between State jurisdiction and Federal jurisdiction. In all honesty, shedding load for local area impacts has nothing to do with BES reliability and should not be under FERC jurisdiction under Section 215 of the Federal Power Act, but rather State jurisdiction for quality of service issues. However, there is also the matter of FERC jurisdiction over commercial matters and the opportunity to “game” the original footnote by transmission providers by allowing firm load shedding to grant firm transmission service for themselves, thereby avoiding or deferring transmission investment, while at the same time denying or requiring others to build the same transmission avoided in order to obtain transmission service. We can see how difficult it is from a drafting team’s perspective in achieving a balanced position between these different matters. The drafting team should be applauded for finding a reasonable position.
Response: Thank you for your support.				
Larry E Watt	Lakeland Electric	1	Affirmative	This issue is better handled within the development of the new TPL-001 standard.
Response: The current TPL-002 is in force and will remain so until the completion of the TPL-001-2 effort. This limited scope revision to footnote ‘b’ is to add clarity to what is in effect.				

Consideration of Comments on Project 2010-11: TPL Table 1 Order and Comments Submitted with Initial Ballots

The Standards Committee thanks all commenters who submitted comments on the proposed SAR for the TPL Table 1 Order. The SAR proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

The SAR, implementation plan, and the clean and redline versions to the four TPL standards were posted for a 40-day public comment period from April 15, 2010 through May 27, 2010. Stakeholders were asked to provide feedback on the standards through a special electronic comment form. There were 22 sets of comments, including comments from more than 80 different people from approximately 40 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

The initial ballot for the proposed changes to the four TPL standards was conducted from May 17-27, 2010. The comments submitted with initial ballots and the drafting team's responses to those comments are contained in this report.

All comments submitted during the comment period and the initial ballot results are posted on the following page:

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Based on stakeholder comments, the drafting team has made some additional changes to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT from the cited inputs that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when load could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote 'b' allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote 'b' were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand is appropriate in certain limited circumstances and that such usage is not widespread.
- Use of the term 'fringes' was seen as problematic and application at the 'fringes' could possibly be discriminatory.
- If interruption of non-consequential Demand were not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that requires ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote 'b'. This led to the approach shown in the 2nd posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote 'b' in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote 'b' to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

The above changes will be noted to stakeholders in a separate posting before the initiation of another ballot.

The revised Footnote ‘b’ is:

b) An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- Demand that is directly served by the elements that are removed from service as a result of the Contingency

- Interruptible Demand or Demand-Side Management

- Demand that does not adversely impact overall BES reliability where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected.

If you feel that your comment has been overlooked, 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]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Comments and Responses from Formal Comment Period:

Comments and Responses from Initial Ballot:

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, 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, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
4.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
5.	Sylvain Clermont	Hydro-Quebec TransEnergie		1
6.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
7.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
8.	Ben Eng	New York Power Authority	NPCC	4
9.	Brian Evans-Mongeon	Utility Services	NPCC	8
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
11.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
12.	Kathleen Goodman	ISO - New England	NPCC	2
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1
14.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
15. Randy MacDonald			New Brunswick System Operator	NPCC					2				
16. Bruce Metruck			New York Power Authority	NPCC					6				
17. Lee Pedowicz			Northeast Power Coordinating Council	NPCC					10				
18. Robert Pellegrini			The United Illuminating Company	NPCC					1				
19. Saurabh Saksena			National Grid	NPCC					1				
20. Michael Schiavone			National Grid	NPCC					1				
2.	Group	Philip R. Kleckley	South Carolina Electric & Gas	X		X		X					
Additional Member			Additional Organization	Region					Segment Selection				
1. Bob Jones			Southern Company Services - Trans.	SERC					1				
2. David Marler			Tennessee Valley Authority	SERC					1				
3. Charles Long			Entergy	SERC					1				
4. James Manning			North Carolina Electric Membership Corporation	SERC					3				
5. Pat Huntley			SERC Reliability Corporation	SERC					10				
3.	Group	John Bee	Exelon Transmission Strategy & Compliance	X		X		X					
Additional Member			Additional Organization	Region					Segment Selection				
1. Mortenson, Eric			:(ComEd)	RFC					1				
2. Weaver, David W			(PECO)	RFC					1				
3. McHugh, Kathleen P			(PECO)	RFC					1				
4. Kay, Thomas W			(ComEd)	RFC					1				
5. Szymczak, Ronald			(ComEd)	RFC					1				
6. Chu, Ron F			(PECO)	RFC					1				
7. Donnelly, Michael J			(PECO)	RFC					1				
8. Kliros, Chris B			(ComEd)	RFC					1				
9. Mills, Paul M			(ComEd)	RFC					1				
10. Webb, Becky			(ComEd)	RFC					1				
4.	Group	Denise Koehn	BPA, Transmission Reliability Program	X		X		X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

Additional Member	Additional Organization	Region	Segment Selection
1. Chuck Matthews	BPA, Transmission Planning	WECC	1
2. Berhanu Tesema	BPA, Transmission Planning	WECC	1
3. Larry Furumasu	BPA, Transmission Planning	WECC	1
4. Kyle Kohne	BPA, Transmission Planning	WECC	1
5. Don Watkins	BPA, Transmission System Operations	WECC	1
6. Rebecca Berdahl	BPA, Power, Long Term Sales and Purchases	WECC	3

				1	2	3	4	5	6	7	8	9	10
5.	Group	Carol Gerou	Midwest Reliability Organization										X

Additional Member	Additional Organization	Region	Segment Selection
1. Chuck Lawrence	American Transmission Company	MRO	1
2. Tom Webb	Wisconsin Public Service	MRO	3, 4, 5, 6
3. Terry Bilke	Midwest ISO Inc.	MRO	2
4. Jodi Jenson	Western Area Power Administration	MRO	1, 6
5. Ken Goldsmith	Alliant Energy	MRO	4
6. Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
7. Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
8. Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
9. Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
10. Scott Nickels	Rochester Public Utilities	MRO	4
11. Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
6.	Group	Richard Kafka	Pepco Holdings, Inc.	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Jim Summers	Delmarva Power and Light Co.	RFC	1
2. John Radman	Potomac Electric Power Company	RFC	1

				1	2	3	4	5	6	7	8	9	10
7.	Group	Ben Li	IESO		X								

Additional Member	Additional Organization	Region	Segment Selection

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1. Bill Phillips			MISO	MRO									
2. James Castle			NYISO	NPCC									
3. Charles Yeung			SPP	SPP									
4. Lourdes Estrada-Salinero			CAISO	WECC									
5. Patrick Brown			PJM	RFC									
6. Steve Myers			ERCOT	ERCOT									
8.	Group	Frank Gaffney	Florida Municipal Power Agency	X			X	X	X				
Additional Member			**Additional Organization**	**Region**					**Segment Selection**				
1. Timothy Beyrle			Utilities Commission of New Smyrna Beach	FRCC					4				
2. Greg Woessner			Kissimmee Utility Authority	FRCC					1				
3. Jim Howard			Lakeland Electric	FRCC					1				
4. Lynne Mila			City of Clewiston	FRCC					3				
5. Joe Stonecipher			Beaches Energy Services	FRCC					1				
6. Cairo Vanegas			Fort Pierce Utility Authority	FRCC					4				
9.	Individual	Stephen Mizelle	Southern Company Transmission	X									
10.	Individual	Robert Casey	Georgia Transmission Corporation (Bulk System Planning)	X									
11.	Individual	Thad Ness	American Electric Power	X		X		X	X				
12.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
13.	Individual	Martin Bauer	US Bureau of Reclamation					X					
14.	Individual	Kirit Shah	Ameren	X		X		X	X				
15.	Individual	Robert W. Roddy	Dairyland Power Cooperative	X		X		X					

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
16.	Individual	Marty Berland	Progress Energy	X		X		X	X				
17.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X					
18.	Individual	Charles Lawrence	American Transmission Company	X									
19.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
20.	Individual	Bill Middaugh	Tri-State Generation and Transmission Association, Inc.	X		X		X	X				
21.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									
22.	Individual	Dan Rochester	Independent Electricity System Operator		X								

1. The SDT is proposing a revision to footnote 'b' in the TPL tables to comply with FERC Order RM-06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system by June 30, 2010. Do you agree with the proposed changes and if not, please provide specific reasons for your disagreement.

Summary Consideration: The SDT has listened to the comments from the industry, understands the concerns raised, and has made changes to the footnote to balance the various industry concerns while assuring BES reliability.

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT from the cited inputs that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when load could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote 'b' allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote 'b' were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term 'fringes' was seen as problematic and application at the 'fringes' could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote 'b'. This led to the approach shown in this 2^{nd} posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote 'b' in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote 'b' to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial~~

~~Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Duke Energy	No	Duke Energy voted "Negative" on the initial and current ballots of TPL-001-1, primarily because Duke believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We also sought rehearing on the Commission's March 18 Order Setting Deadline for Compliance (Docket No. RM06-16), with respect to this and other issues. We believe that FERC's directive in that Order to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the potential impacts (environmental, historical, archaeological, aesthetic...) of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. Duke offers the following ideas on alternatives for the SDT to consider that will allow for appropriate discretion and facilitate proper planning while allowing non-consequential load loss (NCLL).The standard should allow for dropping of limited amounts of non-consequential load in situations where it would be reasonable for a

Organization	Yes or No	Question 1 Comment
		bounded time period and under restricted system conditions (e.g. 1-3 years only when load is >90 % of peak conditions). Dropping of non-consequential load would be prudent planning in situations where the near term impact of load projections or implementation of nearby transmission/generation projects will alleviate the necessity of an upgrade to meet N-1 conditions. Also, reliability of service to end-use customer is impacted by the entire system from source to load. Where allowance for NCLL would not greatly impact individual end-use customers' level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to avoid projects without greatly impacting a customer's outage frequency and duration should be acceptable. Use of reliability metrics (e.g. SAIFI/SAIDI/ASAI) should also be considered by the SDT for determination of acceptable use of NCLL.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- o Interruptible Demand or Demand-Side Management
- o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Midwest Reliability Organization	No	For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by

Organization	Yes or No	Question 1 Comment
		the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.
Dairyland Power Cooperative	No	DPC concurs with the MRO comments: For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.
American Transmission Company	No	For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.

Response: The SDT has added the second bullet to address your concern.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Georgia Transmission Corporation (Bulk System Planning)	No	Georgia Transmission Corporation (GTC) believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We believe that FERC's directive in (Docket No. RM06-16) to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. We also note that on April 19 NERC filed a request for rehearing with FERC asking that the Commission revise the directive in Paragraph 8 of the March 18 TPL-002 Order to allow NERC the necessary time to incorporate changes to the TPL-002 Reliability Standard through the Reliability Standards Development Process that are necessary to achieve bulk power system reliability. NERC also requested that the Commission grant NERC's Motion for Stay to stay the Order so that a public technical conference with opportunity for comment can be held in order to provide parties an opportunity to meet and discuss the technical considerations of developing a modification to the TPL-002 standard that prohibits the loss of non-consequential firm load in the event of an N-1 contingency. NERC's April 19 filing pointed out that if the Commission's directive to disallow the loss of non-consequential firm load for an N-1 contingency is implemented, a question is presented regarding whether the Reliability Standard still serves the purpose of ensuring the Reliable Operation of the bulk power system by preventing instability, uncontrolled separation, and cascading failures. That is, the Commission's directive sets forth an expectation that NERC is to implement standards that address all loss of load at costs that may not be commensurate with bulk power system reliability, as statutorily defined, which is fundamentally different from what the Reliability Standards were intended to do.
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the		

Organization	Yes or No	Question 1 Comment
various industry concerns while assuring BES reliability. . Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Progress Energy	No	Progress Energy applauds NERC's efforts to improve the footnote (b) language with respect to conditional allowance of curtailing Firm Transmission Service, which is addressed in the second paragraph of the proposed new footnote (b). PE remains concerned, however, that the first paragraph of the proposed new footnote (b) does not allow for curtailment of non-radial non-consequential load. The ability to curtail non-consequential load in the planning horizon can be a useful tool to mitigate local area issues, and has not been detrimental to the Bulk Electric System (BES). Disallowing the curtailment of non-radial non-consequential load essentially prohibits taking action in situations in which the load in question is clearly at a localized self-contained level of the system, i.e. the distribution system(s) served by the Transmission Owner/Operator. Prohibiting the curtailment of local load thus constitutes regulating distribution feeder reliability rather than BES reliability. Events that could be mitigated through the curtailment of local, non-radial non-consequential load are infrequent, and such curtailment has no material effect on the reliability of the BES.

Organization	Yes or No	Question 1 Comment
		PE therefore suggests that the following addition (item (3)) to the first paragraph of the proposed footnote (b) be considered:"No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, and/or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities, and/or (3) Planned or controlled interruption of any additional Load required to mitigate the post-contingency results, provided that the non-consequential load being shed for the event is localized, and provided that the total load shed for the event does not exceed 2% of the Planned system peak demand or 200 MW, whichever value is less."

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The SDT did not adopt numerical limits as a single nation-wide value was not seen as equitable for all entities.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Hydro-Québec TransEnergie	No	The proposed changes do not adequately address FERC's concerns in RM06-16-009. The Commission

Organization	Yes or No	Question 1 Comment
(HQT)		again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." The proposed changes to footnote 'b' indicate "No interruption of firm Load is allowed except:... (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities." The exception described appears to still allow non-consequential load loss. FERC describes in RM06-16-009 non-consequential load loss as "the removal, by any means, of any firm load that is not directly served by the elements that are removed from service as a result of the contingency." In referencing Order 693, the Commission reiterated its position that TPL standards "should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency." "Must" should be used instead of "should" in the last sentence of the footnote, making it to read "Facility Ratings in those regions must also be respected."
Northeast Power Coordinating Council	No	The proposed changes do not adequately address FERC's concerns in RM06-16-009. The Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." The proposed changes to footnote 'b' indicate "No interruption of firm Load is allowed except:... (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities." The exception described appears to still allow non-consequential load loss. FERC describes in RM06-16-009 non-consequential load loss as "the removal, by any means, of any firm load that is not directly served by the elements that are removed from service as a result of the contingency." In referencing Order 693, the Commission reiterated its position that TPL standards "should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency." "Must" should be used instead of "should" in the last sentence of the footnote, making it to read "Facility Ratings in those regions must also be respected."
Response: The SDT believes that it has been responsive to the FERC directive in that the standards development process has been employed. In the development of the footnote, the SDT has balanced the need for discretion while addressing local area concerns with the need to assure the reliability of the BES.		

Organization	Yes or No	Question 1 Comment
‘Must’ is not appropriate in a footnote as it would impose a requirement in the footnote. The SDT has replaced ‘should’ with ‘would’ to correct the grammar. Footnote ‘b’ now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Tri-State Generation and Transmission Association, Inc.	No	Tri-State does believe that the new footnote is an improvement, but thinks there are still some changes necessary. We believe that the word “only” should be removed from the phrase “...where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities” because that discrimination was not required in FERC Order RM-06-16-009. There may be times when facilities near the temporary radial facilities might also fall outside the limits set in reliability criteria but the situation is mitigated if the load shedding occurs at the radial facility. The meaning of the second paragraph of the new footnote is unclear. Tri-State recommends changing it to "Curtailment of Firm Transmission Service is not allowed unless it is coupled with curtailment-offsetting resources that are obligated to re-dispatch. Further, the curtailment activities cannot result in the shedding of any Firm load or in violations of Facility Ratings, either internal or external to the planning region."
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td colspan="3">various industry concerns while assuring BES reliability.

The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

Footnote ‘b’ now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~

o Interruptible Demand or Demand-Side Management

o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.</td></tr>
<tr><td>Southern Company Transmission</td><td>No</td><td>We propose that the section in double parentheses be deleted. The proposed wording by the drafting team seems to imply that the curtailment of firm transmission service is permitted to address single contingency constraints if coupled with the redispatch of network resources. The original language stated only that curtailments were permitted to prepare for the next contingency, not to address loading related to the initial contingency. The proposed wording could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint.

Southern Companies recommend that the original language relating to “preparing for the next contingency” be incorporated into the drafting team’s proposal.((Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		curtailments of contracted Firm (non-recallable reserved) electric power Transfers.)) No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch. where it can It must be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

Response: The SDT believes that System re-dispatch is an acceptable System adjustment to "remain within applicable Facility Ratings" to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the firm transfers cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

Organization	Yes or No	Question 1 Comment
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South Carolina Electric & Gas	Yes	For better clarity delete the phrase “when coupled with” in the second paragraph of footnote ‘b.’
Response: The SDT did not delete the suggested phrase as it believes it is correct as stated but added commas to make the phrase read more clearly. Footnote ‘b’ now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Independent Electricity System Operator	Yes	IESO supports the revisions made to footnote ‘b’ based on the present definitions of BES and Firm Demand and on the understanding that the NERC standards apply only to the BES as defined in the NERC Glossary as follows:”As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.” To be clear, our interpretation of the present definition of BES is

Organization	Yes or No	Question 1 Comment
		that it defers to each Regional Reliability Organization to define the elements of the power system that are considered BES and, therefore in the NPCC Region, "BES as defined by NERC" = "BPS as defined by NPCC".
Response: The SDT agrees that the standard applies to the BES as defined in the Glossary.		
BPA, Transmission Reliability Program	Yes	On the firm transfer issues, the term "Firm Transmission Service" should be replaced with "Firm Transfers" to be consistent with the fourth column of the existing Table 1 Transmission System Standards - Normal and Emergency Conditions.
Response: The SDT agrees and has made the change. Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
American Electric Power	Yes	

Organization	Yes or No	Question 1 Comment
Exelon Transmission Strategy & Compliance	Yes	
Florida Municipal Power Agency	Yes	
IESO	Yes	
Northeast Utilities	Yes	
Pepco Holdings, Inc.	Yes	
US Bureau of Reclamation	Yes	
Manitoba Hydro	Yes	MH agrees with the SDT proposal.
Ameren	Yes	We were ok with the previous language. Though we do not intend to drop non-consequential load for a single contingency, we undersatnd that other ares may have been following such practice without degarding the relaibility of BES. We believe that they can continue this practice if they develop non-firm contracts with these customers.
Response: Thank you for your support. Several stakeholders proposed additional modifications and the drafting team did make several additional modifications to the footnote – please see the revised footnote.		

2. Are you aware of any conflicts caused by compliance with the proposed language in Table 1 — footnote b and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement? If yes, please identify the conflict.

Summary Consideration: The SDT understands that there may be conflicts as pointed out by respondents; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES. Strict numerical constraints applied across all of North America were not seen as appropriate. Instead, the SDT is leveraging existing processes to require documentation of Demand to be interrupted including alternatives evaluated and for the situation to be vetted in an open and transparent stakeholder process.

Footnote ‘b’ now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

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Organization	Yes or No	Question 2 Comment
Ameren	No	

Organization	Yes or No	Question 2 Comment
American Electric Power	No	
American Transmission Company	No	
BPA, Transmission Reliability Program	No	
Dairyland Power Cooperative	No	
Exelon Transmission Strategy & Compliance	No	
Independent Electricity System Operator	No	
Manitoba Hydro	No	
Midwest Reliability Organization	No	
Southern Company Transmission	No	
US Bureau of Reclamation	No	
South Carolina Electric & Gas	No	The comments expressed herein represent a consensus of the views of the above named members of the SERC Engineering Committee Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.
Response: Thank you for your response. Several stakeholders proposed additional modifications and the drafting team did make several additional modifications to the footnote – please see the revised footnote.		
Hydro-Québec TransEnergie (HQT)	Yes	Conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict

Organization	Yes or No	Question 2 Comment
		between state and federal positions could place utilities in a compromising position.
Northeast Power Coordinating Council	Yes	Conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.
IESO	Yes	It should be noted that conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. In RM-06-16-009, the Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." In the US, State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.Similar conflicts may also exist in Canada.
Progress Energy	Yes	There is the potential for conflict between Table 1 - Footnote (b) as currently proposed, which can be considered to regulate local distribution reliability without improving BES reliability, and local service reliability issues which are under the purview of state regulatory agencies. For example, the North Carolina Utilities Commission (NCUC) commented regarding this concern in the ballot which ended March 1 in Project 2006-02. Specifically, NCUC commented that they were "...concerned that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1 is an inappropriate overreach into service issues that are more appropriately addressed by state regulatory commissions..." Progress Energy believes that NCUC's concerns are legitimate. BES reliability should address the avoidance and mitigation of cascading outages and BES facility damage, rather than limited, controlled local area loss of load, in order to avoid this conflict and overlap of regulation.
Response: The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES. Strict numerical constraints applied across all of North America were not seen as appropriate. Instead, the SDT is leveraging existing processes to require documentation of Demand to be interrupted including alternatives evaluated and for the situation to be vetted in an open and transparent stakeholder process.		

Organization	Yes or No	Question 2 Comment
Northeast Utilities	Yes	Northeast Utilities (NU) believes the language of the proposed revision to footnote 'b' can be better defined as the proposed revision is subject to interpretation by the different entities and regulatory agencies. Future conflicts can be minimized by further clarifying the proposed revision. Also, NU is concerned that this new modification does not specify the amount of permissible load shed nor does it require the planning entity to minimize load shedding under this exception.
Response: The SDT has made several clarifying changes to the footnote which should alleviate your concerns. Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Duke Energy	Yes	See response to question #1.
Georgia Transmission Corporation (Bulk System Planning)	Yes	See response to Question #1.

Organization	Yes or No	Question 2 Comment
Response: See response to question #1.		
Florida Municipal Power Agency	Yes	This is an area of fuzziness between State jurisdiction and Federal jurisdiction. In all honesty, shedding load for local area impacts has nothing to do with BES reliability and should not be under FERC jurisdiction under Section 215 of the Federal Power Act, but rather State jurisdiction for quality of service issues. However, there is also the matter of FERC jurisdiction over commercial matters and the opportunity to "game" the original footnote by transmission providers by allowing firm load shedding to grant firm transmission service for themselves, thereby avoiding or deferring transmission investment, while at the same time denying or requiring others to build the same transmission avoided in order to obtain transmission service. We can see how difficult it is from a drafting team's perspective in achieving a balanced position between these different matters. The drafting team should be applauded for finding a reasonable position.
Pepco Holdings, Inc.	Yes	This is not an issue for historic PJM members, but as PJM has expanded and as a result of the merger of historic councils into RFC, I am aware that not all regions had standards equal to those of MAAC, and this has been an issue worked out between transmission planners (historic transmission owners) and their local regulators. It is ultimately a cost issue for loss of local load that does not affect the overall reliability of the interconnected BES.
Response: Thank you for your support.		
Tri-State Generation and Transmission Association, Inc.	Yes	We believe that FERC's directive in FERC Order RM-06-16-009 to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load.
Response: The SDT is not in a position to comment on FERC's authority. The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES. Such constraints would be determined through the open and transparent stakeholder process.		

3. Consideration of Comments on Initial Ballot — TPL Table 1 Order (Project 2010-11) May 17–27, 2010

Summary Consideration: The SDT has listened to the comments from the industry, understands the concerns raised, and has made changes to the footnote to balance the various industry concerns while assuring BES reliability.

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT from the cited inputs that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when load could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote 'b' allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote 'b' were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could

you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this 2nd posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that likely will be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

Footnote ‘b’ now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~

o Interruptible Demand or Demand-Side Management

o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch do~~es~~ not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Rodney Phillips	Allegheny Power	1	Negative	Allegheny Power believes the loss of non-consequential load and/or curtailment of transmission service for N-1 contingencies should be limited to only extreme circumstances. Exception 2 of footnote b allows for the loss of non-consequential load for N-1 contingencies with no restriction. Allegheny Power recommends removing exception 2 footnote b.
Response: The SDT and the majority of the commenters disagree with this suggestion.				
Gordon Rawlings	BC Transmission Corporation	1	Negative	BCTC appreciates the good work of the SAR committee in drafting the changes to Footnote b of Table 1. BCTC agrees with the drafting team that interruption of firm load, served by either radial circuits or circuits that have became radial as a result of the contingency, should be allowed for N-1 contingencies. However, it is our position that interruption of firm load should not be limited only to such consequential loads. In our view, interruption of electric supply to some local network customers in the affected area should be permissible. This inclusion will allow transmission planners to plan BCTC's regional transmission network reliably and without impacting neighbouring transmission networks.
Faramarz Amjadi	BC Transmission Corporation	2	Negative	
Hubert C. Young	South Carolina Electric & Gas Co.	3	Negative	SCE&G has significant concern with the proposed revision to TPL Table 1, Footnote B. The current Footnote B states "Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted

Voter	Entity	Segment	Vote	Comment
				element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems". The phrase "without impacting the overall reliability of the interconnected transmission systems" is important to the TPL standards to ensure that ERO standards do not dictate the level of service to customers. Service to customers and load pockets is jurisdictional to State Commissions and ERO standards should not compromise this jurisdiction. SCE&G believes that any proposed revisions to Footnote B must retain the concept that planned or controlled interruption of electric supply to customers, whether they are radial or network, is allowed as long as it does not impact the overall reliability of the interconnected transmission systems. The proposed revision eliminates this concept. There seems to be a general inconsistency and maybe confusion between the terms "reliability" and "level of service".
David Frank Ronk	Consumers Energy	4	Negative	The current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the previous version of TPL-001-1. However, it still does not allow Transmission Planners to use appropriate and necessary discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should control the decision making when BES reliability is not an issue. Often, the consequences of these events are solely local in nature, requiring only minor additional loss of local load to avoid the costly major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load.
James B Lewis	Consumers Energy	5	Negative	
Hugh A. Owen	Public Utility District No. 1 of Chelan County	6	Negative	The interruption of a small amount of load is, under most conditions, not a risk to the reliability of the BES and is at times necessary to preserve reliability. The planned interruption of some load may be a cost effective alternative to a costly transmission project. That is a quality of service issue.
Michael Gammon	Kansas City Power & Light Co.	1	Negative	While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit
Charles Locke	Kansas City Power & Light Co.	3	Negative	
Thomas Saitta	Kansas City Power & Light Co.	6	Negative	

Voter	Entity	Segment	Vote	Comment
				point of view to allow loss of non-consequential load.
Linda Brown	San Diego Gas & Electric	1	Affirmative	As to item (1), all load served directly by a transmission element which experiences a fault will be interrupted when the faulted element is taken out of service. This is the natural relationship between the load and the transmission element. Allowing this for BES elements may encourage transmission owners to remove transmission instead of upgrading or replacing it. Consider a load supplied by two transmission lines of different capacity. If the larger line is lost due to a contingency (N-1) and the remaining smaller line overloads the transmission owner is left with several options to address the problem: (1) move load between buses, (2) upgrade the smaller line, (3) add another line, or (4) create a radial load by removing the smaller line. Number (4) may be the least expensive and allowable under TPL-002, footnote b. Item (2) may also encourage transmission owners to develop plans which make load shedding part of category B. Consider a load served by three transmission lines, a utility may decide to remove a line, instead of upgrading, in order to set up a situation where an N-1 contingency would make the bus temporarily radial. In the event of a single outage (N-1), the load bus will be temporarily radial and load can be shed at the bus.
W. R. Schoneck	Florida Power & Light Co.	3	Affirmative	I believe the language is an improvement and clarifies the intent but I believe there still should be additional language added to give an exemption in meeting this requirement if it does not make economic sense(not economically feasible) and has no real impact on the BES.
Richard J Kafka	Potomac Electric Power Co.	1	Affirmative	It is understood that this is a compliance filing issue. This is not an issue for historic PJM members, but as PJM has expanded and as a result of the merger of historic councils into RFC, I am aware that not all regions had standards equal to those of MAAC, and this has been an issue worked out between transmission planners (historic transmission owners) and their local regulators. It is ultimately a cost issue for loss of local load that does not affect the overall reliability of the interconnected BES.
Alan Gale	City of Tallahassee	5	Affirmative	TAL thanks for SDT for the tireless effort to get to this point. TAL is voting affirmative with the following comments. We accept that the loss of non-consequential load is not a desired result for N-1 contingencies. It is also not the norm in system planning or operations. The flexibility to operate the system consistent with “good utility practice” may warrant the “odd-ball” case that would require this to occur. The dropping of non-consequential load

Voter	Entity	Segment	Vote	Comment
				will NOT lead to BES instability, voltage collapse, or cascading outages, which is what FERC and NERC are charged with preventing. It will lead to the shedding of load in a local area only. Utilities do not drop customers lightly. If the meter isn't turning, we are not getting paid, so we want the meter spinning. Utility power, while vital to our normal day-to-day lives and infrastructure, was never intended to be without interruption.
Brad Chase	Orlando Utilities Commission	1	Affirmative	This change raises the bar on transmission system performance. This change applies a blanket requirement upon entities that does not take into account the number of outages, probability of outages or cost to the customer. There are certain to be situations where this blanket requirement will result in increased cost to customers for no noticeable increase in reliability. OUC does agree with the concept of greater clarification on this requirement, however this clarification may raise the bar to far by trying to establish a blanket requirement. Duke, Progress Energy and others will be submitting comments with proposed language that attempt to address some of these issues and we encourage the drafting team to consider those comments.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of

Voter	Entity	Segment	Vote	Comment
				resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Eric Egge	Black Hills Corp	1	Negative	Black Hills believes that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
Chifong L. Thomas	Pacific Gas and Electric Company	1	Negative	PG&E commends the SDT for developing the proposed footnote b. While it is a great improvement over the complete prohibition on loss of non-consequential load for any single contingency, the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system, especially where the impact is local in nature, to avoid instability, cascading or uncontrolled separation. Such planned interruption of load may be a reasonable alternative to the environmental impacts or prohibitive costs associated with a major new transmission project. Given the potential impacts of the proposed modification, further vetting of the issues is needed. PG&E believes that NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.

Voter	Entity	Segment	Vote	Comment
Thomas J. Bradish	RRI Energy	5	Negative	RRI supports the WECC position on this issue; namely, that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
Trent Carlson	RRI Energy	6	Negative	
John Tolo	Tucson Electric Power Co.	1	Negative	The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project.
James Tucker	Deseret Power	1	Negative	The prohibition of loss of non-consequential load for events resulting the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including

Voter	Entity	Segment	Vote	Comment
				customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
Louise McCarren	Western Electricity Coordinating Council	10	Negative	The proposed revisions to footnote b of Table 1 are an improvement to the recently balloted prohibition on loss of non-consequential load for single contingencies. The recognition of the new term "temporarily radial" is a step in the right direction. However, the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
William Mitchell Chamberlain	California Energy Commission	9	Negative	While the proposed revisions to footnote b are an improvement to the prohibition on loss of non-consequential load for a single contingency proposed in the recently failed TPL-001-1 ballot, the prohibition of loss of non-consequential load for events resulting the loss of a single element still inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is

Voter	Entity	Segment	Vote	Comment
				local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
John Mick	Colorado Springs Utilities	6	Negative	Colorado Springs Utilities ballot on the proposed changes to TPL Table 1, footnote b directed in FERC Order RM06-16-009 Colorado Springs Utilities wishes to vote NO on the proposed changes to TPL Table 1, footnote b, directed in FERC Order RM06-16-009. CSU concurs with the WECC position paper for the ballot, and agrees with the WECC statement "that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues".

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

The SDT agreed that a technical conference on this issue would be of value and held such a conference on August 10, 2010.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and

Voter	Entity	Segment	Vote	Comment
				~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Horace Stephen Williamson	Southern Company Services, Inc.	1	Negative	Comments have already been submitted previously, but it will be added here again. Proposed footnote should read... No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers when coupled with the appropriate re-dispatch of resources obligated to re-dispatch. It must be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. The proposed changes are based on the following... "The proposed wording by the drafting team seems to imply that the curtailment of firm transmission service is permitted to address single contingency constraints if coupled with the redispatch of network resources. The original language stated only that curtailments were permitted to prepare for the next contingency, not to address loading related to the initial contingency. The proposed wording could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint. Southern Companies recommend that the original language relating to "preparing for the next contingency" be incorporated into the drafting team's proposal."
Richard J. Mandes	Alabama Power Company	3	Negative	
Anthony L Wilson	Georgia Power Company	3	Negative	
Gwen S Frazier	Gulf Power Company	3	Negative	
Don Horsley	Mississippi Power	3	Negative	
Michael Ibold	Xcel Energy, Inc.	3	Negative	The proposed modification to footnote b of Table I in TPL-001 - 004 standards states that after a Category B contingency, there should not be any thermal, voltage or stability violation, no interruption of firm load (except the load that is directly connected to the elements that are removed from service as a result of the contingency) and no firm transfer curtailment (except when coupled with re-dispatch of resources obligated to re-dispatch). We believe the proposed footnote b creates a gap between TPL-002 and TPL-003 standards, since it does not address conditions when firm load shedding and firm transfer curtailments are not required to meet the system performance for Category B contingency, but one or both are the required system adjustments to prepare for the next contingency (Category C3). When firm transfer is curtailed after the first contingency in
Liam Noailles	Xcel Energy, Inc.	5	Negative	
David F. Lemmons	Xcel Energy, Inc.	6	Negative	

Voter	Entity	Segment	Vote	Comment
				preparation for the next contingency, it is not clear from the proposed footnote b if this is considered a valid system adjustment for Category C or a violation of Category B. Recall that the existing footnote b addresses this condition explicitly by stating "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm Transfers."
George T. Ballew	Tennessee Valley Authority	5	Affirmative	TVA appreciates the work of the SDT on this issue. However, TVA recommends revising the second paragraph of the revised footnote b: "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. However, curtailment of Firm Transmission Service is only allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected." Without the changes in the first two sentences above, the proposed wording by the SDT could be interpreted to allow re-dispatch/firm curtailments to address any single contingency constraint instead of in preparation for the next contingency.
Marjorie S. Parsons	Tennessee Valley Authority	6	Affirmative	
Larry Akens	Tennessee Valley Authority	1	Affirmative	TVA appreciates the work of the SDT. However, TVA recommends revising the second paragraph of the revised footnote "b". Without changes in the first two sentences, the proposed wording by the SDT could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint instead of in preparation for the next contingency.

Response: The SDT believes that System re-dispatch is an acceptable System adjustment to "remain within applicable Facility Ratings" to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the firm transfers cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand.

Voter	Entity	Segment	Vote	Comment
				Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Robert W. Roddy	Dairyland Power Coop.	1	Negative	DPC CONCURS WITH THE MRO COMMENTS.
Jason Shaver	American Transmission Company, LLC	1	Affirmative	For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed if the tripping of the load is either accepted or volunteered by the customer.
Lawrence R. Larson	Otter Tail Power Company	1	Negative	The change precludes the use of direct load control systems that should be allowed to relieve transmission problems. These systems control firm transmission load but rate conditions can allow their use to mitigate transmission problems.
Response: *(Note - MRO did not submit comments with the initial ballot – but did submit the following comment during the formal comment period: For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.)*				

Voter	Entity	Segment	Vote	Comment
The SDT has modified the footnote to address your concern. Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.				
Ajay Garg	Hydro One Networks, Inc.	1	Negative	Hydro One is casting a negative vote for the following reasons: 1. The amendment to the footnote does not add any technical value to the standard. It was added only to satisfy a FERC directive to address comments made to allow non-consequential load loss after a single contingency event, "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." 2. Addressing curtailment of Firm Transmission Service with re-dispatch of resources is a matter of a commercial nature and should be dealt with in the agreements dealing with such services. Issues of contracted transmission services, firm or otherwise, are not a reliability related matter and are not to be dealt with in this standard.
Michael D. Penstone	Hydro One Networks, Inc.	3	Negative	

Voter	Entity	Segment	Vote	Comment
				3. Matters of interruption of firm load should be incorporated into this standard only after the FERC NOPR on the definition of the BES is resolved. As it stands, the footnote will pose significant problems if the 100 kV and above FERC proposal is applied across the board, unless the standard specifically states that it applies to the BES as defined by the region (current definition).

Response: 1. & 2. The SDT disagrees. The SDT believes that there could be a direct impact on reliability of the BES associated with uncontrolled interruption of Demand and that it is important to discourage and limit the use of this option.The SDT has added clarity to the footnote.

Footnote ‘b’ now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

3. The SDT disagrees that this needs to wait on the FERC NOPR. This standard is applicable to the BES as it is defined.

Spencer Tacke	Modesto Irrigation District	4	Negative	I am voting NO vote because of the lack of clarity of the second paragraph of the proposed change. Although paragraph 1 is an improvement to the current wording, and actually allows for some specific flexibility in shedding load for an N-1 event, the lack of clarity in the second paragraph could lead to varied interpretations by members and compliance

Voter	Entity	Segment	Vote	Comment
				auditors. Thank you.

Response: The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Dana Cabbell	Southern California Edison Co.	1	Negative	It is SCE's position that the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local
David Schiada	Southern California Edison Co.	3	Negative	

Voter	Entity	Segment	Vote	Comment
Ahmad Sanati	South California Edison Company	5	Negative	regulator input, for their individual system. When planned load interruption is identified as a response to a single event, the impact to the system is often local in nature. The planned interruption of load may be a desirable alternative to the prohibitive costs associated with a major new transmission project. If the NERC Standards Drafting Team decides to proceed with footnote B, as written, it needs to ensure that Transmission Owners, Transmission Operators, and Transmission Planners have enough time to both design and implement any mitigation plans necessary to be compliant with the new language. In almost all cases the actual implementation of a solution requiring new construction will be dependent on a number of different regulatory agencies providing the necessary permits allowing for its construction. As such, NERC needs to ensure that any time frame associated with compliance to the proposed language be variable, and allow for extended implementation time frames based on system conditions that may delay placing mitigation plans in service. An example of a reasonable variable time frame to be compliant with the proposed language in footnote B would be to start the clock 60 months from receiving the pertinent environmental permitting. In California this could be the issuance of a Draft Environmental Impact Review pursuant to the California Environmental Quality Act.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

The SDT has added more latitude for the Transmission Planner with the modifications and believes that 60 months should be sufficient.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the~~

Voter	Entity	Segment	Vote	Comment
				~~Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Henry Ernst-Jr	Duke Energy Carolina	3	Negative	On the initial ballot of TPL-001-1 Duke Energy also voted "Negative", primarily because Duke believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We also sought rehearing on the Commission's March 18 Order Setting Deadline for Compliance (Docket No. RM06-16), with respect to this and other issues. We believe that FERC's directive in that Order to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the potential impacts (environmental, historical, archaeological, aesthetic...) of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. With this "Negative" vote, Duke

Voter	Entity	Segment	Vote	Comment
				offers the following ideas on alternatives for the SDT to consider that will allow for appropriate discretion and facilitate proper planning while allowing non-consequential load loss (NCLL). The standard should allow for dropping of limited amounts of non-consequential load in situations where it would be reasonable for a bounded time period and under restricted system conditions (e.g. 1-3 years only when load is >90 % of peak conditions). Dropping of non-consequential load would be prudent planning in situations where the near term impact of load projections or implementation of nearby transmission/generation projects will alleviate the necessity of an upgrade to meet N-1 conditions. Also, reliability of service to end-use customer is impacted by the entire system from source to load. Where allowance for NCLL would not greatly impact individual end-use customers' level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to avoid projects without greatly impacting a customer's outage frequency and duration should be acceptable. Use of reliability metrics (e.g. SAIFI/SAIDI/ASAI) should also be considered by the SDT for determination of acceptable use of NCLL.
Luther E. Fair	Gainesville Regional Utilities	1	Affirmative	Even though I am voting in the affirmative, I agree that most of the comments offered by Duke and Norther Indiana in their earlier statements have merit and should be considered. Also, I believe that the use of reliability metrics should be considered by the SDT for determination of acceptable use of NCLL.
Mace Hunter	Lakeland Electric	3	Negative	Reliability should consider the entire system from source to load. Where allowance for NCLL would not greatly impact individual end-use customer's level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to delay projects without greatly impacting a customer's outage frequency and duration should be acceptable. Use of reliability metrics should also be considered by the SDT for determination of acceptable use of NCLL.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

Voter	Entity	Segment	Vote	Comment
				Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Sammy Roberts	Progress Energy Carolinas	1	Negative	Progress Energy applauds NERC's efforts to improve the footnote (b) language with respect to conditional allowance of curtailing Firm Transmission Service, which is addressed in the second paragraph of the proposed new footnote (b). PE remains concerned, however, that the first paragraph of the proposed new footnote (b) does not allow for curtailment of non-radial non-consequential load. The ability to curtail non-consequential load in the planning horizon can be a useful tool to mitigate local area issues, and has not been detrimental to
Lee Schuster	Florida Power Corporation	3	Negative	

Voter	Entity	Segment	Vote	Comment
Sam Waters	Progress Energy Carolinas	3	Negative	the Bulk Electric System (BES). Disallowing the curtailment of non-radial non-consequential load essentially prohibits taking action in situations in which the load in question is clearly at a localized self-contained level of the system, i.e. the distribution system(s) served by the Transmission Owner. Prohibiting the curtailment of local load thus constitutes regulating distribution feeder reliability rather than BES reliability. Events that could be mitigated through the curtailment of local, non-radial non-consequential load are infrequent, and such curtailment has no material effect on the reliability of the BES. PE therefore suggests that the following addition (item (3)) to the first paragraph of the proposed footnote (b) be considered: "No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, and/or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities, and/or (3) Planned or controlled interruption of any additional Load required to mitigate the post-contingency results, provided that the non-consequential load being shed for the event is localized, and provided that the total load shed for the event does not exceed 2% of the Planned system peak demand or 200 MW, whichever value is less."
Wayne Lewis	Progress Energy Carolinas	5	Negative	

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The SDT did not adopt a numerical limit as it believes that any single numerical value applied on a ntion-wide basis was not equitable for all entities.

Footnote 'b' now reads:

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- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial~~

Voter	Entity	Segment	Vote	Comment
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Timothy VanBlaricom	California ISO	2	Negative	The California ISO supports NERC's request for a public technical conference to be held, as described in NERC's April 19, 2010 request for rehearing and motion for stay of the March 18 Order (RM06-16-009), to provide the opportunity to gain industry input and written comments regarding the Commission's TPL-002-0 directive for NERC to develop a modification to the TPL-002-0 Table 1 footnote b.
Response: The SDT agreed that a technical conference would be of value and held such a conference on August 10, 2010.				
Terry L. Blackwell	Santee Cooper	1	Negative	The Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning processes appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. Table B footnote still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, and local customers should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. The Commission's directive sets forth an expectation that NERC is to implement standards that address all loss of load at costs that may not be commensurate with bulk power system reliability, as statutorily defined, which is fundamentally different from what the Reliability Standards were intended to do.
Zack Dusenbury	Santee Cooper	3	Negative	
Suzanne Ritter	Santee Cooper	6	Negative	

Voter	Entity	Segment	Vote	Comment
Response: The SDT is not in position to comment on FERC's authority. The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.				
Kimberly J. Jones	North Carolina Utilities Commission	9	Negative	The NC Utilities Commission is concerned that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1, and as explained in draft footnote b, is an inappropriate overreach into service issues that are more appropriately addressed by state regulatory commissions. This requirement does not provide any benefit to reliability of the bulk electric system and could undermine state efforts to balance reliability issues with cost of service issues. The standard should continue to allow Transmission Planners to use discretion regarding loss of non-consequential load, understanding that state commissions are positioned to force electric utilities to address local service quality issues on an expedited basis, should it be necessary and in the public interest.
Response: The SDT understands the concern but believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES. The SDT's approach will leverage existing processes to document and vet the situation. Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the				

Voter	Entity	Segment	Vote	Comment
Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.				
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Negative	THE PROPOSED INTERPRETATION WILL UNDERMINE THE INTERNATIONAL STANDARDS SETTING PROCESS AND COULD RESULT IN DIFFERING INTERPRETATIONS OF STANDARDS ON THE NORTH AMERICAN BULK-POWER SYSTEM.
Response: The SDT disagrees and believes that the footnote has been clarified appropriately within the standards development process.				
Daryn Barker	Louisville Gas and Electric Co.	6	Negative	The revised footnote b on Table 1 imposes additional requirements on the responsible entities. The footnote states: Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. However, R1 states: The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned These statements address different and inconsistent scope. If the change in scope was intended then a change should also be made to R1 to reconcile the inconsistency.
Charlie Martin	Louisville Gas and Electric Co.	5	Negative	Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. However, R1 states: The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned These statements address different and inconsistent scope. If the change in scope was intended then a change should also be made to R1 to reconcile the inconsistency.
Response: The SDT agrees that your assessment is for your portion of the interconnected grid. However, when performance in one system is dependent on generation dispatch in another system or vice versa, the SDT believes that one must ensure that the re-dispatch is feasible. The SDT does not believe that this presents a conflict with Requirement R1.				
John Apperson	PacifiCorp	3	Negative	This proposal warrants a "no" vote due to the current uncertainty regarding the outcome of the FERC TPL-002 NOPR issued by FERC on March 18, 2010. The impacts of the proposed changes to footnote B cannot be assessed separately from the alternative interpretation of TPL-002 proposed by FERC. The proper planning of a transmission system requires that all performance requirements are known and understood. If only some of the requirements are known and understood it is impossible to properly plan, study, assess, and operate the

Voter	Entity	Segment	Vote	Comment
				transmission system.
Response: The current TPL-002 is in force and will remain so until the completion of the cited FERC NOPR. This limited scope revision to footnote 'b' is to add clarity to what is in effect.				
Keith V. Carman	Tri-State G & T Association Inc.	1	Negative	Tri-State does believe that the new footnote is an improvement, but thinks there are still some changes necessary. We believe that the word "only" should be removed from the phrase "...where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities" because that discrimination was not required in FERC Order RM-06-16-009. There may be times when facilities near the temporary radial facilities might fall outside the limits set in reliability criteria but the situation is mitigated if the load shedding occurs at the radial facility. The meaning of the second paragraph of the new footnote is unclear. Tri-State recommends changing it to "Curtailment of Firm Transmission Service is not allowed unless it is coupled with curtailment-offsetting resources that are obligated to re-dispatch. Further, the curtailment activities cannot result in the shedding of any Firm load or in violations of Facility Ratings, either internal or external to the planning region." We believe that FERC's directive in FERC Order RM-06-16-009 to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load.
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.				

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
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The SDT is not in position to comment on FERC’s authority.</td></tr>
<tr><td>Claudiu Cadar</td><td>GDS Associates, Inc.</td><td>1</td><td>Negative</td><td>We do not agree with the proposed changes due to several reasons. Although the proposed change will directly influence the reliability standards and transmission system performances, will also have an indirect impact on the economic side with respect to the expansion of existing transmission system. We believe that FERC directive as stipulated in Order 693 cannot constrict, nor impose certain actions outside of the reliability limits. We believe that since these events are merely isolated and rarely enforced, the decision of mandating a great financial effort as a consequence of the proposed changes would certainly be counterbalanced by its feasibility when compare with the current cost of load shedding. While the revised footnote b can be certainly considered an improvement from the current version, however it still does not allow the joined entities involved to have power over the decision making when BES reliability is not an issue.

We also believe that any mandatory changes implemented in the TPL standards under the</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
				current scenario are not entirely feasible unless all other issues such as the definition of the BES, Consequential / Non-consequential Load, BES Critical Element, etc gets resolve ahead. The revision with respect to load shedding, specifically the portion about shedding loads on newly radial facilities, does not match the version 1 TPL standard definition of consequential load loss. To approve the proposed revision to footnote 'b' would create an unnecessary discrepancy between the version 1 TPL standard under consideration and the existing standards. We recognize that the Version 1 will replace Version 0, but since it appears that the performance standard with respect to footnote 'b' is intended to be same in the revised footnote and the Version 1 standard, it only makes sense that the revised version 0 footnote 'b' match the consequential load loss definition contemplated in Version 1. In the light of the above we suggest the Commission to approach different other solutions and ideas for improving the current reliability of the transmission system without enforcing decisions beyond its statutory scope. We advance an alternative to this matter meant to balance the reliability of the transmission system and its indirect financial impact. Although the solution that we offer would require an extended time for development and implementation, however we urge NERC to consider it in its further approach. Our alternative consists mainly in implementing an additional term such as "Critical Load" which we have briefly figured that would consist in particular load necessary to be maintained in service without interruption. Even though this new term would seemed to be at first related with the quality of the service, however a joint association of transmission planners, customers, regulatory entities as decision makers can simply individualize the load that cannot be shed, as well as future transmission improvements that will be required to serve this envisioned small amount of load rather than the entire load. In this way we will create a reasonable balance in between the reliability of the transmission system and the cost to maintain / improve this reliability.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When

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Ronald D. Schellberg	Idaho Power Company	1	Negative	While the proposed revisions are an improvement to the prohibition on loss of non-consequential load for a single contingency proposed in the recently failed TPL-001-1 ballot, that the prohibition of loss of non-consequential load for events resulting the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. However, the removal of: "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers." will require significant adjustments in either TRM or TTC reductions to be compliant with this revised standard in the WECC Region. To construct additional transmission facilities to maintain present day business could easily exceed 10 Billion dollars throughout the WECC region. For example, the Pacific AC Intertie currently has a TTC of 4800 MW spread across 3 500 kV transmission lines. With the loss of one Transmission line, the Pacific AC intertie drops to 3200 MW. Removal of this sentence

Voter	Entity	Segment	Vote	Comment
				would require TP either to drop the Firm TTC of the Intertie to 3200, or include a TRM reservation of at least 1600 MW. The TPs would not be able to say that a loss of 1600 MW of import capacity would not result in curtailments of firm load. Just about all multi transmission line paths in the WECC Region would suffer. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. In the case of long interties between subregions of WECC, these interties have never been planned to operate in this manner. Idaho Power recommends that the sentence permiting system adjustments be reinserted into Footnote B.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

The SDT believes that System re-dispatch is an acceptable System adjustment to "remain within applicable Facility Ratings" to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the firm transfers cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the

Voter	Entity	Segment	Vote	Comment
Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.				
Francis J. Halpin	Bonneville Power Administration	5	Affirmative	For consistency, regarding the firm transfer issue, the term "Firm Transmission Service" should be replaced with "Firm Transfers" in order to be consistent with the fourth column of the existing Table 1 "Transmission System Standards - Normal and Emergency Conditions".
Response: The SDT agrees and has made the change. Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application				

Voter	Entity	Segment	Vote	Comment
				is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Kim Warren	Independent Electricity System Operator	2	Affirmative	IESO supports the revisions made to footnote 'b' based on the present definitions of BES and Firm Demand and on the understanding that the NERC standards apply only to the BES as defined in the NERC Glossary as follows: "As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighbouring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition." To be clear, our interpretation of the present definition of BES is that it defers to each Regional Reliability Organization to define the elements of the power system that are considered BES and, therefore in the NPCC Region, "BES as defined by NERC" = "BPS as defined by NPCC".
Response: The SDT agrees that the standard applies to the BES as defined in the Glossary.				
Jacquie Smith	ReliabilityFirst Corporation	10	Affirmative	If this revision is an urgent action, then the implementation timeframe should be shorter. In the clarification paragraph below, I do not understand the first sentence. Are there commas missing? What is the requirement and what is the exception? Also, I question the validity of using "should" in the second sentence. If it is a requirement, then it needs to be stated as a requirement. If it is a suggestion, then it does not belong in the standard. No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.
Response: This was originally classified as an 'urgent action' revision to meet the FERC due date which was June 30, 2010, not because NERC had classified the modification as urgent for reliability. Note that FERC modified the due date to March 31, 2011 - this allows several more months of				

Voter	Entity	Segment	Vote	Comment

development time and the SAR was revised to indicate that the proposed modification to footnote 'b' is no longer an Urgent Action revision.

Commas have been added as appropriate and a re-wording was made which should make this clear.

'Should' has been replaced by 'would' to provide additional clarity.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
David H. Boguslawski	Northeast Utilities	1	Affirmative	Northeast Utilities (NU) believes the language of the proposed revision to footnote 'b' can be better defined as the proposed revision is subject to interpretation by the different entities and regulatory agencies. Future conflicts can be minimized by further clarifying the proposed revision. Also, NU is concerned that this new modification does not specify the amount of permissible load shed nor does it require the planning entity to minimize load shedding under this exception.

Response: The SDT has made several clarifying changes to the footnote which should alleviate your concerns.

Voter	Entity	Segment	Vote	Comment

. Footnote ‘b’ now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Donald S. Watkins	Bonneville Power Administration	1	Affirmative	On the firm transfer issues, the term "Firm Transmission Service" should be replaced with "Firm Transfers" to be consistent with the fourth column of the existing Table 1 Transmission System Standards - Normal and Emergency Conditions.
Rebecca Berdahl	Bonneville Power Administration	3	Affirmative	
Brenda S. Anderson	Bonneville Power Administration	6	Affirmative	

Response: The SDT agrees and has made this change.

Footnote ‘b’ now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand.

Voter	Entity	Segment	Vote	Comment
				Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Frank Gaffney	Florida Municipal Power Agency	4	Affirmative	Please see FMPA comments submitted through the concurrent comment period for Project 2010-11
David Schumann	Florida Municipal Power Agency	5	Affirmative	
Response: Please see the response to FMPA comments above.				
Carter B Edge	SERC Reliability Corporation	10	Affirmative	The footnote makes clearer when load can be dropped for planning purposes. By making this footnote more specific, it supports reliability and helps stakeholders apply the TPL standards.
Response: Thank you for your support.				

Voter	Entity	Segment	Vote	Comment
Timothy Beyrle	City of New Smyrna Beach Utilities Commission	4	Affirmative	This is an area of fuzziness between State jurisdiction and Federal jurisdiction. In all honesty, shedding load for local area impacts has nothing to do with BES reliability and should not be under FERC jurisdiction under Section 215 of the Federal Power Act, but rather State jurisdiction for quality of service issues. However, there is also the matter of FERC jurisdiction over commercial matters and the opportunity to "game" the original footnote by transmission providers by allowing firm load shedding to grant firm transmission service for themselves, thereby avoiding or deferring transmission investment, while at the same time denying or requiring others to build the same transmission avoided in order to obtain transmission service. We can see how difficult it is from a drafting team's perspective in achieving a balanced position between these different matters. The drafting team should be applauded for finding a reasonable position.
Response: Thank you for your support.				
Larry E Watt	Lakeland Electric	1	Affirmative	This issue is better handled within the development of the new TPL-001 standard.
Response: The current TPL-002 is in force and will remain so until the completion of the TPL-001-2 effort. This limited scope revision to footnote 'b' is to add clarity to what is in effect.				

Consideration of Comments on TPL Table 1 Order (footnote 'b') — Project 20010-11

The TPL Table 1 Order Drafting Team thanks all commenters who submitted comments on the revised footnote. These standards were posted for a 30-day informal public comment period from September 8, 2010 through October 8, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 42 sets of comments, including comments from more than 96 different people from approximately 75 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

Comments can be reviewed in their original format on the following project page:

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Industry response was divided in relation to support for the proposed footnote 'b' which was posted for an informal comment period through October 8, 2010. Although there were a number of supporters for the proposed footnote they were outnumbered by the commenters who did not support the footnote text for various reasons and offered their views and concerns.

The Standard Drafting Team (SDT) carefully considered the feedback provided including minority opinions such as not allowing Demand interruption at all and has made clarifying revisions to the footnote 'b' text.

The revised footnote 'b' is:

b) An objective of the planning process ~~is to avoid~~ should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. ~~Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process~~. However, it is recognized that Demand ~~may need to~~ will be interrupted if it is directly served by the elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- ~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~
- Interruptible Demand or Demand-Side Management
- ~~Demand that does not adversely impact overall BES reliability where the c~~Circumstances ~~describing~~ where the use of ~~such~~ Demand interruption are documented, including alternatives evaluated; and where the ~~application~~ Demand interruption is subject to review ~~and acceptance~~ in an open and transparent stakeholder process that includes addressing stakeholder comments.

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Based on the review of comments received and the fact that only clarifying changes were made due to those comments, the SDT is recommending that this project be moved forward to balloting.

If you feel that your comment has been overlooked, 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]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, 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, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council	10									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Micahel Schiavone	National Grid	NPCC	1
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Dean Ellis	Dynegy Generation	NPCC	5
8.	Brian Evans-Mongeon	Utility Services	NPCC	8
9.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
10.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	Chantel Haswell	FPL Group, Inc.	NPCC	5
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1
14.	Michael R. Lombardi	Northeast Utilities	NPCC	1

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

15.	Randy MacDonald	New Brunswick System Operator	NPCC	2
16.	Bruce Metruck	New York Power Authority	NPCC	6
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	Saurabh Saksena	National Grid	NPCC	1

2.	Group	Philip R. Kleckley	SERC Planning Standards Subcommittee	1, 3, 5

Additional Member	Additional Organization	Region	Segment Selection	
1.	Bob Jones	Southern Company Services - Trans	SERC	1
2.	John Sullivan	Ameren	SERC	1
3.	Charles Long	Entergy	SERC	1
4.	Jim Kelley	PowerSouth Energy Cooperative	SERC	1
5.	Pat Huntley	SERC Reliability Corporation		10

3.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	WPS Corporation	MRO	3, 4, 5, 6
4.	Jason Marshall	Midwest ISO Inc.	MRO	2
5.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
6.	Ken Goldsmith	Alliant Energy	MRO	4
7.	Alice Murdock	Xcel Energy	MRO	1, 3, 5, 6
8.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
9.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
10.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
11.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
12.	Scott Nickels	Rochester Public Utilties	MRO	4
13.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment
4.	Group	Denise Koehn	Bonneville Power Administration	1, 3, 5, 6

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chuck Matthews	BPA, Transmission Planning	WECC	1
2.	Berhanu Tesema	BPA, Transmission Planning	WECC	1
3.	Kyle Kohne	BPA, Transmission Planning	WECC	1
4.	Kendall Rydell	BPA, Transmission Planning	WECC	1
5.	Rebecca Berdahl	BPA, Long Term Sales and Purchases	WECC	3

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment
5.	Group	Louis Slade, Jr.	Dominion	1, 3, 5, 6

	Additional Member	Additional Organization	Region	Segment Selection
1.	Angela Park	Electric Transmission	SERC	1, 3
2.	John Loftis	Electric Transmission	SERC	1, 3
3.	Mike Garton	Electric Market Policy	NPCC	5, 6
4.	Michael Gildea	Electric Market Policy	RFC	5, 6

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment
6.	Group	Ben Li	IRC Standards Review Committee	2

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Phillips	MISO	MRO	2
2.	Partick Brown	PJM	RFC	2
3.	James Castle	NYISO	NPCC	2
4.	Mark Thompson	AESO	WECC	2
5.	Charles Yeung	SPP	SPP	2
6.	Greg Van Pelt	CAISO	WECC	2
7.	Matt Goldberg	ISO-NE	NPCC	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Individual	Jana Van Ness	Arizona Public Service Company	X		X		X					
8.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
9.	Individual	John Cummings	PPL Corp	X		X		X					
10.	Individual	Andy Tillery	Southern Company	X		X							
11.	Individual	Don Gilbert	JEA	X		X		X					
12.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
13.	Individual	Laura Zotter	ERCOT ISO		X								
14.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
15.	Individual	Steve Stafford	Georgia Transmission Corporation	X									
16.	Individual	John Canavan	NorthWestern Energy	X									
17.	Individual	Tim Ponseti	TVA Transmission Planning & Compliance	X		X		X				X	
18.	Individual	Gordon Rawlings	BC Hydro	X	X	X		X					
19.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				
20.	Individual	John Sullivan	Ameren	X		X		X	X				
21.	Individual	Darcy O'Connell	California ISO		X								
22.	Individual	Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
23.	Individual	Orlando A Ciniglio	Idaho Power	X		X		X					
24.	Individual	Michael Lombardi	Northeast Utilities	X		X		X					
25.	Individual	Thad Ness	American Electric Power	X		X		X	X				
26.	Individual	JC Culberson	ERCOT		X								
27.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
28.	Individual	Charles Lawrence	American Transmission Company	X									
29.	Individual	Kathleen Goodman	ISO New England Inc.		X								
30.	Individual	Dan Rochester	Independent Electricity System Operator		X								
31.	Individual	Ed Davis	Entergy Services	X		X		X	X				
32.	Individual	Terry Harbour	MidAmerican Energy	X		X		X	X				
33.	Individual	Patrick Farrell	Southern California Edison Company	X		X		X	X				
34.	Individual	Jonathan Appelbaum	United Illuminating Co	X									
35.	Individual	Michael Moltane	ITC	X									
36.	Individual	Gregory Campoli	New York Independent System Operator		X								
37.	Individual	David Kiguel	Hydro One Networks Inc.	X		X							
38.	Individual	Jason Marshall	Midwest ISO		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
39.	Individual	Claudiu Cadar	GDS Associates Inc.	X									
40.	Individual	Chifong Thomas	Pacific Gas and Electric Co.	X		X		X					
41.	Individual	Catherine Koch	Puget Sound Energy	X									
42.	Individual	Harold Wyble	Kansas City Power & Light	X		X		X	X				

1. The SDT is proposing a revision to footnote 'b' in the TPL tables to comply with FERC Orders which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Do you agree with the proposed changes and if not, please provide specific reasons for your disagreement.

Summary Consideration: Industry response was divided in relation to support for the proposed footnote 'b' which was posted for an informal comment period through October 8, 2010. Although there were a number of supporters for the proposed footnote they were outnumbered by the commenters who did not support the footnote text and offered their views and concerns.

The Standard Drafting Team (SDT) carefully considered the feedback provided and has made clarifying revisions to the footnote 'b' text. For each major item, the SDT has addressed the issue raised and has summarized any revision made to footnote 'b' in response to the feedback provided. The SDT appreciates industry input and believes the changes made are responsive to the comments received.

Open and Transparent Process: Most of the comments received related to the use of an "open and transparent" stakeholder process as described in the proposed footnote 'b'. While the comments on this topic varied, the majority of comments indicated that such a process should not be included within a mandatory Reliability Standard and cited that FERC Order 890 already requires the sharing of planning information. Others indicated that the statement for "review and acceptance" exceeds expectations required by FERC Order 890 and that an entity's compliance to a Reliability Standard should not be subject to the "acceptance" of stakeholders and that a process conforming with FERC Order 890 principles already requires dispute resolution. Some commenters expressed support of the process and it is noted that those who responded "Yes" with no comment were assumed to support the process "as is".

The SDT's inclusion of a stakeholder review in footnote 'b' was driven by the fact that FERC Order 890 does not fully cover the continent-wide footprint addressed by a NERC Reliability Standard. Additionally, footnote 'b' is being applied to address localized Bulk Electric System performance and not a wide-area Bulk Electric System concern that is generally the focus of the "open and transparent" process governed by FERC Order 890.

The SDT thoroughly considered all comments on the stakeholder process model. The SDT continues to support a Reliability Standard providing mandatory enforcement utilizing a stakeholder process where any intended use of planned Demand interruption has transparency and that stakeholders have the opportunity to comment on its use. However, upon further reflection the majority of SDT members agreed that including the "acceptance" aspect of the stakeholder process presents challenges within the context of a Reliability Standard and "acceptance" has been removed. The SDT agrees with opinions that an entity's compliance should not be subject to the "acceptance" of its plans by stakeholders. Also, the SDT realizes that for most entities there is a final, high level review with acceptance or approval of Transmission plans at the local level. So, while the footnote no longer references the need for stakeholder acceptance, the expectation is that there will be a review process in place that will consider the implementation of any plan calling for Demand interruption as explained in the footnote.

In addition, the SDT has revised footnote 'b' to explicitly require a response to any challenges presented via the stakeholder process.

Demand vs. Load: Several commenters questioned the SDT's use of the term "Demand" instead of "Load" in the proposed footnote. The SDT clarifies that this was intentional as the existing, approved TPL suite of standards uses the term Demand throughout the requirement text. Additionally, the existing, approved TPL performance requirements documented in Table I contain the column heading "Loss of Demand or Curtailed Firm Transfers" which is the subject of the footnote 'b' applicability for category B (single element) Contingencies. This project, Project 2010-11, aims to address footnote 'b' regulatory directives with no change to the remainder of the standard. Therefore, for consistency with the existing standard text, the term Demand is retained.

Firm transfer vs. Firm Transmission Service: Some stakeholders suggested that the SDT revert back to the use of "Firm Transmission Service" instead of the undefined term "firm transfers." The SDT clarifies that that the change to "firm transfers" was intentional as the existing, approved TPL suite of standards references "firm transfers" both in requirement text and Table I. The existing, approved TPL performance requirements documented in Table I contain the column heading "Loss of Demand or Curtailed Firm Transfers" which is the subject of the footnote 'b' applicability for category B (single element) Contingencies. This project, Project 2010-11, aims to address footnote 'b' regulatory directives with no change to the remainder of the standard. Therefore for consistency with the existing standard text, the term 'firm transfer' is retained.

Amount of Demand Loss: The majority of commenters agree with the SDT's clarifications regarding interruption of Demand as defined in the proposed footnote 'b'. The majority of entities who commented support the limited use of Demand interruption and that when used to address a BES performance requirement agree that it should be documented, and made known through a stakeholder process. However, as stated above, the majority stopped short of supporting a mandatory Reliability Standard requiring "acceptance" by other entities for the planned interruption of Demand.

Other minority views propose to limit or cap the amount of Demand loss and some suggested 50 MW as the appropriate level. Some felt the SDT's prior approach of limiting the Demand loss to only "radial" line configurations was appropriate and superior to the "open process" approach. It is also noted that some commenters went further to say no loss of Demand should be allowed for a single Contingency, but this was clearly a minority view of the comments submitted.

The SDT carefully considered the comments and unanimously agreed that defining a Demand level limit is problematic based on the vast differences in BES applications across the continent and that each potential use is case specific. The SDT also had concerns that setting such a limit may have the unintended consequences of planned Demand interruption being more widely accepted in practice in Transmission planning. The SDT and most commenters are of the opinion that a stakeholder review process is a better deterrent for Demand interruption and will appropriately guard against any misuse.

The revised footnote 'b' is:

b) An objective of the planning process ~~is to avoid~~ should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. ~~Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process~~. However, it is recognized that Demand ~~may need to~~ will be interrupted if it is directly served by the elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- ~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~
- Interruptible Demand or Demand-Side Management
- ~~Demand that does not adversely impact overall BES reliability where the c~~Circumstances ~~describing~~ where the use of ~~such~~ Demand interruption are documented, including alternatives evaluated; and where the ~~application~~ Demand interruption is subject to review ~~and acceptance~~ in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	1. The introductory paragraph discourages the Interruption of any Demand, implying that no Demand directly connected should be interrupted. However, it is an acceptable practice to allow for some Interruption of Demand that is directly connected to the element that is removed from service. Recommend that the drafting team revise the wording to eliminate this implication, and soften the expectation such that it is recognized that some Interruption of Demand is unavoidable by system configuration, but that each entity should establish a reasonable limit on how much demand can be interrupted due to the loss of an element. 2. The Statement that "However, Demand may need to be interrupted in limited circumstances to address BES performance requirements" in the introductory paragraph contradicts bullet 3 "Demand that does not adversely affect BES ..." 3. The third Bullet is confusing. Suggest revising the wording to clarify the adverse impact to the BES system, documentation expectations, and to answer fundamental questions such as who has the authority to decide the use if the stakeholder process is "accepting", and the necessity of having a stakeholder process. It is unlikely that the interruption of Demand will adversely impact the BES system. This constraint is too broad. The language in this bullet also allows that non-consequential Demand interruption could be used to mitigate reliability violations arising from the NERC Category B contingency events (i.e., single element contingencies). 4. In the second paragraph, the conditions when interruption of Firm Transfers may be used are not specified. 5. In the last sentence of the second paragraph, "would" should be replaced by "must". Alternatively, possible rewording of footnote "b" to be considered: b) An objective of the planning process should be to minimize the likelihood of interrupting Demand and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements or other local reasons which have no adverse impact on overall BES reliability or the interconnected BES. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Demand that does not adversely impact overall reliability of the BES or the interconnected BES and where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of available resources, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected. The Drafting Team should reconsider the use of "Load" as opposed to "Demand". By definition (NERC

Organization	Yes or No	Question 1 Comment
		Glossary dated April 20, 2010) Demand is:"1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer."Load is defined as:"An end-use device or customer that receives power from the electric system."This terminology is more appropriate to the application used in the Table.
Hydro One Networks Inc.	No	1. The introductory paragraph discourages the Interruption of any Demand, implying that no Demand directly connected should be interrupted. However, it is an acceptable practice to allow for some Interruption of Demand that is directly connected to the element that is removed from service. Recommend that the drafting team revise the wording to eliminate this implication, and soften the expectation such that it is recognized that some Interruption of Demand is unavoidable by system configuration, but that each entity should establish a reasonable limit on how much demand can be interrupted due to the loss of an element. 2. The Statement that "However, Demand may need to be interrupted in limited circumstances to address BES performance requirements" in the introductory paragraph contradicts bullet 3 "Demand that does not adversely affect BES ..." 3. The third Bullet is confusing. Suggest revising the wording to clarify the adverse impact to the BES system, documentation expectations, and to answer fundamental questions such as who has the authority to decide the use if the stakeholder process is "accepting", and the necessity of having a stakeholder process. It is unlikely that the interruption of Demand will adversely impact the BES system. This constraint is too broad. The language in this bullet also allows that non-consequential Demand interruption could be used to mitigate reliability violations arising from the NERC Category B contingency events (i.e., single element contingencies). 4. In the second paragraph, the conditions when interruption of Firm Transfers may be used are not specified. 5. In the last sentence of the second paragraph, "would" should be replaced by "must". Alternatively, possible rewording of footnote "b" to be considered: b) An objective of the planning process should be to minimize the likelihood of interrupting Demand and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements or other local reasons which have no adverse impact on overall BES reliability or the interconnected BES. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Demand that does not adversely impact overall reliability of the BES or the interconnected BES and where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of available resources, where it can be demonstrated that Facilities remain within

Organization	Yes or No	Question 1 Comment
		applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected. The Drafting Team should reconsider the use of “Load” as opposed to “Demand”. By definition (NERC Glossary dated April 20, 2010) Demand is:”1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.”Load is defined as:”An end-use device or customer that receives power from the electric system.”This terminology is more appropriate to the application used in the Table.
SERC Planning Standards Subcommittee	No	The revised text relating to the planning process exceeds what is appropriate for a reliability standard. Existing open and transparent stakeholder processes focus on larger system issues and not on local load serving. We suggest the following: Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Interruptible Demand or Demand-Side Management o Demand that does not adversely impact overall BES reliability and is made temporarily radial as a result of the Contingency, where that Demand must be interrupted to meet performance requirements. Curtailment of firm transfers is allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected. “ The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.”
Ameren	No	The revised text to footnote b relating to the planning process exceeds what is appropriate for a reliability standard. Existing open and transparent stakeholder processes focus on larger system issues rather than on local load serving issues. We suggest the following text for footnote b:Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Interruptible Demand or Demand-Side Management o Demand that does not adversely impact overall BES reliability and is made temporarily radial as a result of the Contingency, where that Demand must be interrupted to meet performance requirements. Curtailment of firm transfers is allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the

Organization	Yes or No	Question 1 Comment
		re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.
MRO's NERC Standards Review Subcommittee	No	The revised draft is a significant improvement over the first draft. However, we suggest the following minor changes: 1. The criterion of "adversely affect overall BES reliability" is undefined and maybe subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest adding the words "as defined by each Transmission Planner or Planning Authority". 2. The term of "firm transfers" is undefined and maybe subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest establishing a definition for the term, reverting to the "Firm Transmission Service" term, or using another appropriate defined term.
American Transmission Company	No	The revised draft is a significant improvement over the first draft. However, we suggest the following minor changes: 1. The criterion of "adversely affect overall BES reliability" is undefined and may subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest adding the words "as defined by each Transmission Planner or Planning Authority". 2. The term of "firm transfers" is undefined and may subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest establishing a definition for the term of "firm transfers", reverting to the "Firm Transmission Service" term, or using another appropriate NERC defined term.
PacifiCorp	No	PacifiCorp believes that the current version of footnote "b" is an improvement over the language that currently exists in the standard, except for one component of the revised footnote. The third bullet in the draft standard currently limits the interruption of Demand if it does not adversely impact overall BES reliability, where the circumstances describing the use of the interruption are documented (including alternatives evaluated) and the application is subject to review and acceptance in "an open and transparent stakeholder process." PacifiCorp believes that the language requiring review and acceptance of an application of demand interruption through any sort of stakeholder process should be removed. It is not practical or effective to prescribe that either this standard or any other standard requires stakeholder approval in order to maintain compliance. As presently drafted, this requirement for stakeholder review and acceptance appears to be inconclusive and indeterminate as to what is required for registered entities to comply. Instead, this third bullet should require the documentation, by the Planning Authority and Transmission Planner, of the circumstances describing the use of Demand interruption - including methodologies used, assumptions relied upon, and alternatives evaluated - as part of the Planning Authorities' and/or Transmission Planners'

Organization	Yes or No	Question 1 Comment
		documentation of results in their annual Reliability Assessments. These annual assessments are already submitted to the appropriate Regional Reliability Organization pursuant to TPL-002-1b Requirement R3. This annual assessment can be provided by the ERO to other appropriate third parties upon their request.
Southern Company	No	The revised text relating to the planning process exceeds what is appropriate for a reliability standard. Existing open and transparent stakeholder processes focus on larger system issues and not on local load serving. We suggest that the drafting team go back to the concept of local load being the load that is made temporarily radial by the contingency. That was a much better approach.
JEA	No	The requirement in general is acceptable; however, there needs to be an added "such as" clause to the referenced "...in an open and transparent stakeholder processes." I suggest adding "..."...in an open and transparent stakeholder processes such as the FERC approved regional 890 process that includes the load serving entity affected".
South Carolina Electric and Gas	No	SCE&G believes the first sentence "An object of the planning process is to avoid interruption of Demand." goes beyond what is appropriate for a reliability standard and therefore should be deleted. Also, the part of the sentence that states "and where the application is subject to review and acceptance in an open and transparent stakeholder process" goes beyond what is appropriate for a reliability standard and should be deleted.
NorthWestern Energy	No	In addition to the three bullet items, add a fourth bullet item to the list of limitations under the body of footnote b: “In no case will a total loss of load that is less than 50 MW be considered a violation of this standard.”
TVA Transmission Planning & Compliance	No	TVA supports FERC's actions on improving reliability of the BES; however, TVA believes that the new proposal is focusing more on reliability of local loads than on the overall reliability of the BES. Footnote b should focus only on the overall reliability of the BES. Reliability of local loads should be addressed outside the TPL standards and therefore should not be used/referenced in footnote b. Also existing stakeholder processes (referred to in the SDT proposal) typically focus on larger system issues and not on local load serving. Thus TVA believes that some local load should be allowed to be dropped in order to maintain BES reliability. However TVA does believe that there should be a limit of how much load can be dropped in order to maintain BES reliability. TVA believes that 50 MW is a reasonable number for this limit. Based on the above, TVA proposes substituting the following for the revised footnote b:Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: Demand that is directly served by the elements that are removed from service as a result of the Contingency Interruptible Demand or Demand-Side Management Demand that does not adversely impact overall BES reliability, where that Demand (not to exceed 50 MW)

Organization	Yes or No	Question 1 Comment
		must be interrupted to meet performance requirements. Curtailment of firm transfers is allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.
BC Hydro	No	The SDT is to be commended for their efforts to develop clear, unambiguous language for Footnote "b". From the discussions that have taken place it seems that there are many different perspectives and to get agreement on specific language will be very difficult. We believe that it would be useful to identify the main issues that Footnote "b" needs to address and we consider those main issues to be: o Definitions of (a) Consequential Load Loss, (b) Firm Demand, (c) Firm Transmission Capability (as distinct from the OATT term, "Firm Transmission Service"), (d) Firm Transfer (this could be defined as transfers using the OATT's Firm Transmission Service, (e) Manual System Adjustments (capitalized in the Category C section of TPL-001, but not defined in the NERC Glossary) and (f) the Bulk Electric System (BES). o Identifying permissible Demand/Transfer curtailment actions for (a) the planning studies simulating the Category B event itself and (b) the planning studies associated with determining acceptable actions for preparing for the next set of contingencies should the initial single contingency be prolonged (ie, last several weeks). This would define the acceptable (pre-emptive) "Manual System Adjustments" of Category C events. o Define separate acceptable curtailment actions for (a) curtailment of Demand (ie, end-user load) and (b) curtailment of market to market transfers, that very rarely, if ever, result in the loss of any end-user load. o Define the planning studies required to determine the acceptability of the impacts on the BES resulting from curtailments in a "remote" part of the system that have been accepted by those directly affected by those curtailments. At this point we don't have specific language to suggest, but we do have the following comments that we hope will help: A. Interruption of Demand: A.1. Consider improving the definition of "Firm Demand" in the NERC Glossary that now reads, "That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions". Perhaps it could be changed to something like, "That portion of the Demand that the planned transmission system must be able to supply without interruption for Category B events. A.2. Consider stating in Footnote "b" that curtailment of Firm Demand is (a) not permitted in the simulation of the N-1 event itself and (b) it is not permitted as part of the (pre-emptive) "Manual System Adjustments" needed to prepare for the next set of contingencies should the initial single contingency be prolonged (ie, last

Organization	Yes or No	Question 1 Comment
		several weeks). B. Interruption of Firm Transfers: B.1. "Firm Transfers" could be defined as transfers using the OATT's Firm Transmission Service, but consider developing a system reliability-based term for "Firm Transmission Capability" instead of referring to the tariff-based NERC definition of "Firm Transmission Service". This would recognize the difference between planning standards and commercial/tariff rules. The NERC definition of "Firm Transmission Service" is now, "The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption". Transmission tariffs address the priority of curtailments when the loading on a transmission path needs to be reduced for whatever reason (single- or multiple-contingencies). The NERC transmission planning standards need a system reliability definition like, "Firm Transmission Capability" is the transmission capability across a cut-plane, on a defined transmission path or across a defined flowgate that is available, before any manual corrective actions are taken, following the worst Category B event under the most onerous normal system conditions considering all plausible generation dispatch patterns and the full range of expected load levels." B.2. Consider stating in Footnote "b" that curtailment of Firm Transfers is only permitted to the extent that redispatch of generation can be implemented so that delivery to the Firm Transfer recipient is not interrupted (a) in the planning studies of the Category B event itself and (b) as part of the (pre-emptive) "Manual System Adjustments" needed to prepare for the next set of contingencies should the initial single contingency be prolonged (ie, last several weeks). C. General Comments: C.1. Consider replacing the first bullet of the proposed Footnote "b" with simply "Consequential Load Loss" since the NERC Project 2006 02 (TPL 001) Standard Drafting Team is introducing the following definition: Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault C.2. Consider removing "Demand-Side Management" (DSM) from the second bullet because that term is too general. The present definition of DSM in the NERC Glossary is:"The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use". C.3. Consider being more specific on what constitutes acceptable "Interruptible Demand", like: "Interruptible Demand that is part of an automatic real-time Direct Control Load Management (DCLM) system that is activated by the contingencies that require it and that is a completely "dual-redundant" scheme including all communications equipment. The DCLM system must result in automatic curtailment of Demand that is fast enough to maintain all BES system performance standards (eg, voltage stability, voltage dip, etc)".

Organization	Yes or No	Question 1 Comment
		C.4. Consider eliminating the description of how interrupting Demand that does not adversely impact overall BES reliability was accepted (ie, the stakeholder process, etc). If such a process were undertaken and it resulted in acceptance that the Demand could be curtailed for Category B events, wouldn’t that simply mean that the Demand was “Interruptible Demand”. It really doesn’t matter what process resulted in it being accepted. The key considerations are that (a) if the interruption of that Demand is necessary to maintain BES reliability, then it must be interrupted in a very reliable manner (ie, dual redundant scheme, etc) and (b) if the interruption of that Demand is not necessary to maintain the reliable performance of the BES, then that should be confirmed by the planning studies (ie, it doesn’t need to have an expensive, sophisticated, dual-redundant DCLM scheme since the impact on the BES is acceptable even if the scheme doesn’t work). D. Additional Questions related to Curtailment of Firm Transfers: In the past, the latter part of Footnote B read: “To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.”The last part of the proposed Footnote B now reads: “Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected.”We would like to understand the implications of the proposed Footnote B as it relates to curtailment of Firm Transfers (as per definition proposed earlier) for the following questions: 1) In the most recent draft of Footnote B, why was the NERC defined term ‘Firm Transmission Service’ replaced with the non-defined term ‘firm transfers’? 2) In the most recent draft of Footnote B, why was the tone softened from “No curtailment of Firm Transmission Service is allowed, except...” to “Curtailment of firm transfers is allowed when...”? 3) Assuming an outage of a single transmission line (N-1 Category B event) has occurred and assuming that no “resources [are] obligated to redispatch” for this outage, would a transmission provider be allowed to curtail Firm Transmission Service (NERC defined term) that it has sold in order to prepare to withstand the next worst credible contingency? 4) Would transmission providers be allowed to sell Firm Transmission Service on a path above what could be delivered with any one element of that path out of service and a range of operating conditions? 5) If the proposed Footnote B is approved, would utilities have to reinforce their system (within 60 months) to ensure that Firm Transmission Service for particular paths would not be curtailed can be delivered when any one element of that path is out of service? 6) If a transmission provider employs Generation Dropping for single contingencies in order to support Firm Transmission Service between regions, and assuming there are no provisions for obligated re-dispatch, would

Organization	Yes or No	Question 1 Comment
		the proposed Footnote B force a recalculation of firm vs non-firm transfer capability? 7) Path 66 (PACI) and Path 65 (PDCI) can both see significant derates in their firm transfer capability for single contingencies. How would the proposed Footnote B impact Firm Transmission on these paths?
FirstEnergy	No	FirstEnergy appreciates the efforts of the Assess Transmission Future Needs SDT in reaching a reasonable proposal for clarifying Table 1 footnote B presented in the TPL-001 through TPL-004 standards. We also commend NERC staff for convening an industry technical conference to discuss the topic and FERC staff for their participation in the technical conference as the industry carefully considered various perspectives. The proposed footnote B is much improved from the prior draft proposals. One change that FirstEnergy proposes is to strike the text following the semicolon in the third bullet item which states "and where the application is subject to review and acceptance in an open and transparent stakeholder process." This text may be intended as explanatory but has the appearance of mandating an approval process that will be auditable through the TPL reliability standards. The statement is not needed within the framework of mandatory reliability requirements as FERC Order 890 already mandates an open and transparent process related to the planning of the bulk electric system. FERC via the 890 Final Rule modified the pro forma Open-Access Transmission Tariff to require open and transparent stakeholder process to better ensure no undue discrimination and access to the transmission system. The Final Rule beginning at paragraph 418 discusses reform to the Coordinated, Open and Transparent Planning of the transmission system. The Commission direction included eight planning principles required to be within the open process - one of which is dispute resolution. It should be well understood that the transmission planner and planning coordinator share and disseminate all of their planning study results and proposed corrective actions - including the proposed use of Demand interruption - as part of their adherence to Order 890. We appreciate the SDT's careful consideration of our comments.
Northeast Utilities	No	NU agrees with the language of the proposed revision to Footnote b EXCEPT FOR bullet #3 which suggests that non-consequential demand interruption could be used to mitigate reliability violations arising from the NERC Category B contingency events (i.e., single element contingencies).
ERCOT	No	The introductory paragraph of footnote b includes policy language. Since this is a reliability standard-and not a policy directive-the general narrative setting forth the desired policy goal of minimizing load-shedding is misplaced. Including policy language can cloud the specific issues the standard attempts to address, and ERCOT recommends deleting the first two sentences in the introductory paragraph. The next sentence in the introductory paragraph goes on to state, generally, that demand may be interrupted to "address BES performance requirements." This phrase is vague. To which performance requirements does this refer? The intent is not clear. If the intent is to generally recognize the need to shed load to respect

Organization	Yes or No	Question 1 Comment
		NERC standards and to allow flexibility for an entity to exercise discretion relative to meeting BES performance requirements, then that intent should be clearly reflected in the language. Furthermore, the last sentence of the introductory paragraph and the subsequent bullet points are arguably inconsistent with this approach, because they could be viewed as removing an entity’s flexibility/discretion by limiting the circumstances when load can be shed. The second bullet point is unnecessary, because it is already apparent that interruptible demand/demand side management programs can be used according to their terms. This could create confusion in that it could be implied that, absent the need to use these to meet BES performance requirements, using them otherwise is inconsistent with/not allowed under footnote b. Simply put, those products are not load shedding as contemplated by this footnote. Therefore they should not be listed here. With respect to the third bullet point, the phrase "demand that does not adversely impact overall BES reliability" is not adequately defined, and provides opportunity for confusion. This is an ambiguous phrase and can’t be linked back to objective NERC standards/requirements. The bullet points should avoid ambiguity to mitigate ambiguity risk in audits. In addition, the last part of the language in this bullet imposing an open and transparent stakeholder process is unclear. What is the intent behind requiring review in a stakeholder process? If it is to establish the ability of the entity to develop load shedding procedures beyond those explicitly contemplated in footnote b, ERCOT questions if it is reasonable for the responsible entity to be required to get “permission” from stakeholders to implement reliability measures related to its obligation as the functional entity. Again, the language simply is not clear. Accordingly, ERCOT recommends this bullet point be removed. If it is retained, it should be revised consistent with these comments to remove ambiguous language to mitigate potential confusion around the meaning/scope of the footnote in the administration of the CMEP. In addition, ERCOT recommends revising the draft footnote b to allow for planned Demand interruption as a means of mitigation during interim periods when a unanticipated (such as unexpected demand growth or unit retirements) or temporary change on the system occurs in a timeframe that is shorter than the time necessary to plan and implement the system upgrades necessary to avoid the Demand interruption. Finally, in the last paragraph of footnote b, it isn’t clear why “Transmission Service” was changed to “transfers.” Firm transmission service is a service provided in some regions, and it provides relative value to other types of services-e.g., non-firm and network. The mention of transmission service may also be irrelevant in this footnote, since the allowance of its interruption doesn't also allow for load shedding. Therefore, ERCOT recommends eliminating the last paragraph of footnote b.
ISO New England Inc.	No	ISO New England does not allow non-consequential load loss for first contingencies in Planning Analysis, and as an overall matter, ISO-NE believes that the appropriate step is for NERC to modify the footnote in line with

Organization	Yes or No	Question 1 Comment
		the original FERC Order. However, ISO-NE offers the following recommendation to improve the proposed language for footnote b if it is to be retained similar to what has been proposed. In short, ISO-NE proposes changing the third sub-bullet, because the provision is both unnecessary and inappropriate for a NERC Standard. First, the sub-bullet is redundant, because the Commission has ordered that companies add to their Open Access Transmission Tariffs an open and transparent planning process. If Transmission Planners establish their system planning assessments through those processes, then there should be no question that the Planner's assessments have been effectively communicated to the region. Second, the passive nature of the language (i.e., "where the application is subject to review and acceptance...") is unclear as it suggests that someone other than the Planning Coordinator/Transmission Planner is responsible for determining what belongs in a long-term system assessment. Including Demand-Side Management in the standard also appears redundant as Demand Response is used as an asset in the same manner as generation resources. b) When interruption of Demand is utilized within the planning process, such interruption is limited to: 1) Demand that is directly served by the elements that are removed from service as a result of the Contingency. 2) Interruptible Demand or Demand-Side Management 3) Instances where the planned or controlled interruption of Demand results in System performance which meets the requirements of Table 1 for Category B contingencies. When such Demand interruption is utilized in an assessment, the use of such actions must be limited to small portions of the system, be operationally achievable, be of limited duration, and be documented therein.
Entergy Services	No	Entergy disagrees with the proposed language in the third bullet for two reasons. 1. While Entergy supports the idea of "an open and transparent stakeholder process" regarding the use of non-consequential load loss. It is unclear how such a process could be fairly implemented as competing stakeholder interests could prevent resolution. Stakeholders should be defined as those stakeholders whose load could be shed per footnote b, not any and all stakeholders. 2. The "is subject to review and acceptance" implies that some formal voting process would be required by stakeholders. Is this the SDT's intent? If so would such a process be developed as part of the standard or would it be left up to TO's? If non-consequential load loss was deemed an acceptable solution across a SEAM, would the TO's jointly serving the load need to agree?

Organization	Yes or No	Question 1 Comment
MidAmerican Energy	No	While the TPL note "b" approach has improved, MidAmerican has concerns that including the wording "review and acceptance" goes beyond the FERC Order 890 order, process, and intent of including the open review process. Therefore, to align with FERC Order 890, the "review and acceptance" should be replaced with "subject to comment". Anything more exceeds FERC Order 890 and the reason why the review process was included. In the end, Transmission Owning and Operating entities must have final say in the operation of the grid. Entities can comment, but cannot obstruct Transmission Owning and Operating entities from properly operating the grid or reliability could be reduced.
United Illuminating Co	No	United Illuminating believes that for TPL Category B contingencies no planned or controlled (non-consequential) interruption of firm demand should occur as a general philosophy for planning the Bulk Electric System (BES). Recognizing there are certain areas of the BES that have unique circumstances that may warrant an exception to this, UI suggests the addition of language that recognizes the limited application of non-consequential load interruption with a process that requires a case-by-case acceptance of such application by the Regional Entity or NERC.
New York Independent System Operator	Yes	The NYISO agrees in principle with the proposed changes, but recommends the following modifications: 1. The introductory paragraph discourages the Interruption of any Demand, implying that no Demand directly connected should be interrupted. However, it is an acceptable practice to allow for some Interruption of Demand that is directly connected to the element that is removed from service. The introductory paragraph is immaterial to the requirement, and therefore unnecessary with the exception of the last sentence which starts the bulleted list. 2. Interruptible demand is an operation tool and not a transmission planning tool, while Demand-Side Management is typically embedded in the load forecast used in the planning process. The second bullet therefore may not be necessary or applicable here, though it is helpful in making clear those are acceptable forms of interruption. 3. The third bullet is confusing. Suggest revising the wording to clarify the adverse impact to the BES system and documentation expectations. Recommend removing reference to the application being subject to review and acceptance in an open and transparent stakeholder process; this is inherent to all documentation and does not need to be emphasized in a footnote. 4. In the last sentence of the last paragraph, "would" should be replaced by "must". 5. The Drafting Team should reconsider the use of "Load" as opposed to "Demand". By definition (NERC Glossary dated April 20, 2010) Demand is: 1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer."Load is defined as:"An

Organization	Yes or No	Question 1 Comment
		end-use device or customer that receives power from the electric system."This terminology is more appropriate to the application used in the Table. Possible rewording of footnote "b" to be considered: b) Under the limited circumstances when interruption of Load is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Load that is directly served by the elements that are removed from service as a result of the Contingency o Interruptible Load or Demand-Side Management o Demand that does not adversely impact overall BES reliability where the circumstances for the use of such Load interruption and alternatives evaluated are documented. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of available resources, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must also be respected.
Midwest ISO	No	Overall, we believe the changes are reasonable. However, we propose to strike "and where the application is subject to review and acceptance in an open and transparent stakeholder process." Stakeholder review processes should not be mandated through enforceable standards as they do not provide a clear benefit to reliability. Further, FERC Order 890 already mandates an open and transparent process related to the planning of the bulk electric system.
GDS Associates Inc.	No	We appreciate all the work conducted by SDT to adjust current footnote "b" however, we disagree with the current approach as follows below:- The definition does not go far enough with recognition that interruption of Demand should be mitigated if at all possible. The previous language may have been inadequate, but the current language does not encourage the TP to develop mitigation plans that could be implemented as an alternative to Demand interruption. - Use of Interruptible Demand should only be implemented if the Transmission Planner can point to a contract between the Transmission Provider and Transmission Customer that permits load curtailment .- Under FERC Order 890, Conditional Firm transmission service can be granted for entities who voluntarily acknowledge the right of the Transmission Provider to curtail their transaction or provide re-dispatch. This should be the only transfer which can be utilized in the Planning Horizon for interruption of Demand for Note b. Suggested language to find the balance point in the tone of this note is below:"An objective of the planning process is to develop mitigation plans that do not call for the curtailment of Demand, as interruption of Demand places specific customer groups at a reliability risk that varies from their counterparts in other areas of the BES. There may be rare instances, however, where interruption of Demand can be considered a short-term bridge to a mitigation plan which does not rely on negatively impacting certain customer segments. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency, o

Organization	Yes or No	Question 1 Comment
		Interruptible Demand or Demand-Side Management, where the Customer has given explicit rights to the Transmission Provider for curtailment of their Demand, o Demand, other than Interruptible Demand or Demand-Side Management, that does not adversely impact overall BES reliability where the circumstances describing the use of such Demand are documented, including alternatives evaluated; where the Load-Serving Entity who has responsibility for serving such Demand has agreed to the curtailment, and where the application is subject to review and acceptance in an open and transparent stakeholder process. Curtailment of Firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch per the terms and conditions of the confirmed transmission service request between the Transmission Customer and Transmission Provider, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of and firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected. In addition, any Conditional Firm transfers may be curtailed, in accordance with the terms and conditions of the confirmed transmission service request between the Transmission Customer and Transmission Provider."
Kansas City Power & Light	No	KCPL appreciates the efforts of the Assess Transmission Future Needs SDT in reaching a reasonable proposal for clarifying Table 1 footnote B presented in the TPL-001 through TPL-004 standards. We also commend NERC staff for convening an industry technical conference to discuss the topic and FERC staff for their participation in the technical conference as the industry carefully considered various perspectives. Although the proposed footnote B is much improved from the prior draft proposals, KCPL proposes is to strike the text following the semicolon in the third bullet item which states "and where the application is subject to review and acceptance in an open and transparent stakeholder process." This text may be intended as explanatory but has the appearance of mandating an approval process that will be auditable through the TPL reliability standards. The statement is not needed within the framework of mandatory reliability requirements as FERC Order 890 already mandates an open and transparent process related to the planning of the bulk electric system. FERC via the 890 Final Rule modified the pro forma Open-Access Transmission Tariff to require open and transparent stakeholder process to better ensure no undue discrimination and access to the transmission system. The Final Rule beginning at paragraph 418 discusses reform to the Coordinated, Open and Transparent Planning of the transmission system. The Commission direction included eight planning principles required to be within the open process - one of which is dispute resolution. It should be well understood that the transmission planner and planning coordinator share and disseminate all of their planning study results and proposed corrective actions - including the proposed use of Demand interruption - as part of their adherence to Order 890.
Puget Sound Energy	Yes	PSE agrees with the foot note b as stated. As it states for any category B outage there wouldn't be any non-consequential load loss allowed unless a full study is performed with evaluation of alternatives and is approved by stakeholders. Also, one could curtail firm transfers if re-dispatch of resource is possible.

Organization	Yes or No	Question 1 Comment
		However, there is still some ambiguity in when approval from stakeholders (time-line) should be sought and who the stakeholders could be (customers, effected utilities etc.). Hence, PSE would like to revise the footnote by adding the following to the end of the footnote, ".... at least 2 years prior to the implementation. All the affected parties must review and agree upon the loss of demand proposal."
Southern California Edison Company	Yes	SCE appreciates the efforts of the NERC Standards Drafting Team and believes that the team has admirably worked to meet FERC's expectations.SCE would suggest that Footnote "b" be revised to include a semi-colon(;) after the first sub-paragraph and a semi-colon(;) followed by an "and" after the second sub-paragraph, to convey that the three sub-paragraphs are alternative, rather than additive methods for satisfying the requirements for "interruptions."
Idaho Power	Yes	footnote 'b' is silent with respect to planned removal from service of certain generators. I believe there are many conditions out there where a single contingency can initiate a planned (RAS-initiated) removal of generation. The fact that this is mentioned in footnote 'c', under multiple contingencies, begs the need for futher elaboration/discussion of this option under single contingencies in footnote 'b'.
Manitoba Hydro	Yes	The changes to Table 1 Note b proposed by the SDT for this second posting are a reasonable approach to the issue of interrupting of "Firm Demand". The requirement to evaluate alternatives to dropping of Firm Demand in a transparent stakeholder process should provide the verification of cost over benefit on a case by case basis. I propose the following editorial changes: 1. The change of "Firm Transmission Services" made in Table 1 should be also be made in each TPL standard as R1 refers to "projected Firm (non-recallable reserved) Transmission Services.2. Since "Firm Demand" is a defined term, ensure it is capitalized throughout the standard. There is one instance where it is not.
California ISO	Yes	1) Regarding the 2nd bullet provision, we suggest: Interruptible Demand or Demand-Side Management that has been reviewed and approved by the Planning Authority. 2) Regarding the 3rd bullet provision, we suggest: Demand interruption that does not adversely impact overall BES reliability.... 3) Also regarding the 3rd bullet provision, we suggest replacing acceptance with clarification to read "where the application is subject to review and clarification in an open and transparent stakeholder process."
Xcel Energy	Yes	Xcel Energy supports the new interpretation that would allow curtailment of firm transfers or demand for limited conditions where the integrity of bulk electric system is not compromised. However Xcel Energy seeks some clarification regarding the following: The 3rd bullet point in footnote b will need to clarify whether the demand interruption can be done after the contingency, or before the contingency. If it is allowed after the

Organization	Yes or No	Question 1 Comment
		contingency, then the standard would allow violation of voltage or thermal loading criteria for a brief period, after contingency and, before demand curtailment happens. Is this acceptable based on the new interpretation? Since TPL-002 standard deals with NERC Category B contingencies, and footnote b states that curtailment of firm transfers is allowed, it should be clarified if this curtailment is allowed before or after the contingency. If the curtailment is allowed only after the contingency, then the system would be in violation of the thermal or voltage criteria for a brief period till the generation is re-dispatched. Is this allowed by the new interpretation? If curtailment is only allowed in preparation of the contingency, then the firm transfers would be curtailed during system intact conditions, in preparation for the first contingency, resulting in violation of TPL-001 standard. Is this allowed by the new interpretation?
PPL Corp	Yes	PPL believes that Footnote b as described in TPL-002-1b, Draft 2, August 30, 2010 is fine provided an accompanying Requirement (with appropriate VRF and VSL) and Measure is added to the TPL standard(s) to require and document notification of the affected Demand parties and the involvement of the affected Demand parties in an open process as described by Footnote b, third bullet.
Duke Energy	Yes	Duke Energy strongly supports this revised footnote ‘b’. We believe that it provides for appropriate consideration of stakeholder input in decision-making for local reliability issues, while maintaining the reliability of the Bulk Electric System.
ITC	Yes	The proposed language for the new TPL-001-1 Table 1 footnote b is acceptable to ITC.
Bonneville Power Administration	Yes	
Dominion	Yes	
IRS Standards Review Committee	Yes	
IRC Standards Review Committee	Yes	
Arizona Public Service Company	Yes	
ERCOT ISO	Yes	

Organization	Yes or No	Question 1 Comment
Georgia Transmission Corporation	Yes	
American Electric Power	Yes	
Independent Electricity System Operator	Yes	
Pacific Gas and Electric Co.	Yes	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on TPL Table 1 Order — Project 2010-11

The TPL Table 1 Order Drafting Team thanks all commenters who submitted comments on the 3rd posting for Project 2010-11: TPL Table 1 Order. These standards were posted for a 45-day public comment period from November 19, 2010 through January 5, 2011. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 27 sets of comments, including comments from more than 67 different people from approximately 30 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

The SDT reviewed all of the comments received and has made a clarifying change to the structure of the footnote to address industry concerns as to the intent of the SDT. No contextual changes have been made to the footnote. Therefore, the SDT is recommending that this project be moved to a recirculation ballot.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

If you feel that your comment has been overlooked, 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]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, 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, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

Additional Member	Additional Organization	Region	Segment Selection	
1.	Al Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Dean Ellis	Dynegy Generation	NPCC	5
8.	Brian Evans-Mongeon	Utility Services	NPCC	8
9.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
10.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	Chantel Haswell	FPL Group, Inc.	NPCC	5
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1

Group/Individual		Commenter	Organization		Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10	

	Additional Member	Additional Organization	Region	Segment Selection
14.	Michael R. Lombardi	Northeast Utilities	NPCC	1
15.	Randy MacDonald	New Brunswick System Operator	NPCC	2
16.	Bruce Metruck	New York Power Authority	NPCC	6
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Charles W. Long	SERC Planning Standards Subcommittee	X									X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Pat Huntley	SERC Reliability Corporation	SERC	10
2.	Bob Jones	Southern Company Services	SERC	1
3.	Darrin Church	Tennessee Valley Authority	SERC	1
4.	Jim Kelley	PowerSouth Energy Cooperative	SERC	1
5.	John Sullivan	Ameren Services Company	SERC	1
6.	Phil Kleckley	South Carolina Electric & Gas Co.	SERC	1

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
4.	Jason Marshall	Midwest ISO Inc.	MRO	2
5.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
6.	Ken Goldsmith	Alliant Energy	MRO	4
7.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
8.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6									
10.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6									
11.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6									
12.	Scott Nickels	Rochester Public Utilties	MRO	4									
13.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6									
14.	Richard Burt	Minnkota Power Cooperative, Inc.	MRO	1, 3, 5, 6									
4.	Individual	Janet Smith	Arizona Public Service Company	X		X		X	X				
5.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
6.	Individual	Andy Tillery	Southern Company	X		X							
7.	Individual	Aaron Staley	Orlando Utilities Commission	X				X					
8.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
9.	Individual	Si Truc PHAN	Hydro-Quebec TransÃ‰nergie	X									
10.	Individual	Tim Ponseti, VP	TVA Trasnmission Plannning & Compliance	X		X		X				X	
11.	Individual	Alex Rost	New Brunswick System Operator		X								
12.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
13.	Individual	Bernie Pasternack	Transmission Strategies, LLC								X		
14.	Individual	Michael A. Curtis, General Counsel	Mohave Electric Cooperative			X							
15.	Individual	David Thorne	Pepco Holding Inc	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
16.	Individual	John Sullivan	Ameren	X		X		X	X				
17.	Individual	Thad Ness	American Electric Power	X		X		X	X				
18.	Individual	Bob Casey	Georgia Transmission Corporation	X									
19.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
20.	Individual	Saurabh Saksena	National Grid	X		X							
21.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
22.	Individual	Jason L. Marshall	Midwest ISO		X								
23.	Individual	Michael Lombardi	Northeast Utilities	X		X		X					
24.	Individual	Dan Rochester	Independent Electricity System Operator		X								
25.	Individual	Gregory Campoli	New York Independent System Operator		X								
26.	Individual	Kathleen Goodman	ISO New England Inc		X								
27.	Individual	Harold Wyble	Kansas City Power & Light	X		X		X	X				

1. The SDT is proposing a revision to footnote 'b' in the TPL tables to comply with a FERC directive which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Do you agree with the proposed changes and if not, please provide specific reasons for your disagreement.

Summary Consideration: The SDT reviewed all of the comments received and has made a clarifying change to the structure of the footnote to address industry concerns as to the intent of the SDT. No contextual changes have been made to the footnote.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

Comment [llh1]: Same comment as in ballot report – we should replace the actuat "track changes" redline with a formatted version of the same, so that we can clean up the margin line indicating track changes.

Organization	Yes or No	Question 1 Comment
SERC Planning Standards Subcommittee	No	The PSS agrees that the proposed language for footnote b provides some additional clarity. While we generally support the concept, we have concerns that the phrase "is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments" remains ambiguous and should be clarified by limiting stakeholder input to those who have load at risk or local regulators obligated to

Organization	Yes or No	Question 1 Comment
		act on their behalf. Revise the first sentence of the last paragraph to read: “To prepare for a second contingency, curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand.”The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Response: The stakeholder process needs to be open and transparent but it is up to the entity to establish the process and whom it may include. No change made. As drafted, footnote ‘b’ clarifies that re-dispatch is allowable to “remain within” ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can only be utilized for a limited time, such as a 2 hour emergency rating. It further clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the firm transfers cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words “To prepare for the next Contingency” to the footnote. No change made.		
Xcel Energy	No	As this is currently drafted, planners would be required to host a forum with stakeholders to discuss hypothetical actions that may be taken in an emergency. We do not see the value in this, nor is it clear who would be considered stakeholders that should attend this forum. For example, we assume it would be the transmission owner’s meeting with distribution providers to discuss the possibility of load shedding. Would that be adequate? Xcel Energy is both a Transmission Planner and a Distribution Provider. In this case would the stakeholder be the end user? This should be struck or more clearly defined.
Response: The stakeholder process needs to be open and transparent but it is up to the entity to establish the process and whom it may include. No change made.		
New York Independent System Operator	No	1. Proposed revised footnote language:b) It is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Interruptible Demand or Demand-Side Management o Circumstances where the uses of firm Demand interruption not directly interrupted by the contingency are documented, including alternatives evaluated; and where the firm Demand interruption is subject to review in an open and transparent stakeholder process. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities

Organization	Yes or No	Question 1 Comment
		remain within applicable Facility Ratings and the re-dispatch does not result in the interruption of any firm Demand. 2. Comments:There are generic concerns with the footnote as amended that must be addressed. The first is the use of the term “Demand”. It is very unclear throughout the footnote whether or not the term Demand includes Interruptible Demand or Demand-Side Management. It is suggested that interruption of Demand be clarified to not include Interruptible Demand or Demand-Side Management to more clearly show the permitted use of that option for load shedding. 3. Further confusion is introduced through the use of the term “firm Demand” in some locations. It is unclear how this is different than the defined term “Firm Demand” and what the implications of the term “firm Demand” are. 4. The first and third sentences of the first paragraph are unnecessary and should be deleted. However, if they are to be retained, the first sentence is unacceptable in its current state. In some instances, Interruptible Demand or Demand-Side Management are utilized in lieu of transmission additions. These can be considered as acceptable mitigation and there is no justification to minimize their use. Therefore some clarification to the term Demand in the first sentence must be made. 5. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. 6. The second portion of the second bullet should be deleted as it is unncessary: “and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.” If this is to be retained, the very last portion should be deleted “that includes addressing stakeholder comments”. The term “addressing” is unclear. This can be misconstrued to infer that plans must be changed in response to stakeholder comments. This may be inappropriate and may be impossible if conflicting comments are received. It may also create a new standard that all comments must be “addressed”, which may not be a part of the stakeholder process across NERC’s footprint. 7. The first sentence of the paragraph under the two bullets seems to prevent a situation where a combination of re-dispatch and the interruption of Demand are utilized. This restriction could prevent a situation where the use of re-dispatch decreases the amount of Demand which must be interrupted. This footnote should not discourage such adjustments which actually increase the reliability of service to end users. 8. This same sentence also uses the term “shedding of firm Demand”. This should be replaced with “Demand interruption” such that it is consistent with the second bullet; otherwise an unnecessary new term has been introduced.

Organization	Yes or No	Question 1 Comment
		9. The last sentence of footnote B is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own. This same thought would have to be added to multiple NERC standards if it was added here, otherwise it would infer that such actions are acceptable in all other standards.

Response: 1. See response to National Grid #1 in ballot comment responses.

2. See response to National Grid #1 in ballot comment responses.

3. See response to National Grid #6 in ballot comment responses.

4. The SDT has reorganized the footnote to clarify its intent and address the issues raised.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

Comment [llh2]: Same comment as in the ballot comment report – I think we should replace the "track changes" redlining with font changes that indicate the same, to clean up document for stakeholders.

5. See response to National Grid #2 in ballot comment responses.

6. See response to National Grid #4 in ballot comment responses.

7. The SDT has reorganized the footnote to clarify its intent and address the issues raised.

8. The SDT has reorganized the footnote to clarify its intent and address the issues raised.

Organization	Yes or No	Question 1 Comment
9. See response to National Grid #7 in ballot comment responses.		
ISO New England Inc	No	1. The following comments are provided in regard to this proposal. The first and third sentences of the first paragraph are unnecessary. While we agree with the concept, it is unclear as to how inclusion of these sentences in a standard creates a measureable requirement. 2. There are generic concerns with the footnote as currently proposed. The first is the use of the term “Demand.” It is unclear whether the term Demand includes Interruptible Demand and Demand-Side Management. It is suggested that interruption of Demand be clarified to exclude Interruptible Demand and Demand-Side Management to more clearly show the permitted use of those options. 3. The second concern is that it is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. 4. The third is that not all areas have stakeholder processes. Documenting the use of Demand Interruption should be sufficient without requiring stakeholder review. Therefore the second portion of the second bullet “including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments” is unnecessary and should be deleted. “Addressing stakeholder comments” introduces undefined actions which may be required in response to the comments. For those areas that already have stakeholder processes, stakeholder comments are by definition addressed. As a result, at a minimum “that includes addressing stakeholder comments” should be deleted. Furthermore, for areas that do not have stakeholder processes, so long as they publish their studies impacted parties are aware of the role of demand response. 5. The fourth is that the second paragraph seems to be restricting the use of Demand interruption for the sake of Firm Transfer reduction. This can be stated directly without adding the confusion of re-dispatch. By coupling re-dispatch with a constraint of not shedding Demand, the paragraph also creates confusion as to what to do in a situation where the amount of Demand that is allowed to be shed in the first paragraph could be reduced with re-dispatch. Would re-dispatch not be allowed? We suggest that the paragraph be rewritten as follows: “Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management).” 6. The fifth is if the term ‘firm demand’ survives the proposed changes; is there an intended distinction between the use of the term “firm Demand” and the defined term “Firm Demand”? If these terms are intended to be differently, it is unclear what the term “firm Demand” represents. 7. The final comment is that the last sentence of footnote B is unnecessary and should be deleted. It is

Organization	Yes or No	Question 1 Comment
		never acceptable to cause reliability concerns in another area while addressing your own. This same thought would have to be added to multiple NERC standards if it was added here, otherwise it would infer that such actions are acceptable in all other standards. 8. If the first and third sentences must be retained the following wording for the footnote is proposed:b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand, (excluding Interruptible Demand or Demand-Side Management), following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Interruptible Demand or Demand-Side Management o Circumstances where the uses of Demand interruption not directly interrupted by the contingency are documented. Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management).

Response: 1. The SDT believes that the first part of the footnote is necessary to provide context for the items that follow and has crafted the language to provide a balance between flexibility and consistency across NERC. No change made.

2. See ballot response to NPCC #1.

3. See ballot response to NPCC #2.

4. The SDT believes that in situations where an entity's planning studies require the interruption of firm load to remain within BES Facility ratings that the entity needs to share those plans in an open and transparent stakeholder process to ensure that other parties that may be adversely impacted by those decisions have the ability to review and comment on those plans. No change made.

5. See ballot response to NPCC #5.

6. The SDT has corrected the indicated errors.

7. See ballot response to NPCC #6.

8. The SDT has reorganized the text in the footnote to address this concern.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited

Organization	Yes or No	Question 1 Comment
circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~ ~~Interruptible Demand or Demand-Side Management~~ ~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~		
Northeast Power Coordinating Council	No	There is concern with the use of the term Demand. It is unclear throughout the footnote whether or not the term Demand includes Interruptible Demand or Demand-Side Management. It is suggested that interruption of Demand be clarified to not include Interruptible Demand or Demand-Side Management to more clearly show the permitted use of Load shedding. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. Language that mitigation of Load and/or Demand interruption should be pursued within the planning process should be reinstated as reinforcement of a Transmission Providers' planning obligations to their load customers, and system operations. Footnote 'b' should be made to read as follows:b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of Load and/or Demand following Contingency events. Interruption of Load and/or Demand is discouraged and all measures to mitigate such interruption should be pursued within the planning process. However, it is recognized that Load and/or Demand will be interrupted if it is directly served by the elements automatically removed from service by the Protection System as a result of a Contingency. Furthermore, in extraordinary circumstances within the planning process Load and/or Demand may need to be interrupted to address BES performance requirements. When interruption of Load and/or Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Circumstances where the use of Load and/or Demand interruption are documented, including alternatives evaluated; and where the Load and/or Demand interruption is made available for review in an open and transparent stakeholder process.If Load and/or Demand interruption is necessary, planning should indicate the amount needed, and not specify how it would be obtained. What Load and/or Demand is

Organization	Yes or No	Question 1 Comment
		interrupted is an operational decision. Additional comments not included in the material listed for footnote ‘b’ on the Comment Form. In the paragraph below the bullets in footnote ‘b’, confusion is introduced through the use of the term “firm Demand”. It is unclear how this is different than the defined term “Firm Demand” and what the implications of the term “firm Demand” are. This footnote should not discourage such adjustments which actually increase the reliability of service to end users. The last sentence of footnote ‘b’ is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own.
Response: This comment is identical to the one made by NPCC in the ballot and the SDT has answered the comment in that forum.		
Arizona Public Service Company	No	It is not clear whether both bullets under "footnote b" have to be met or only one of the two have to be met. It is suggested that the standard be very clear about this.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Southern Company	No	Southern Company is voting "no" on the footnote b ballot because of concerns that the reliability of firm transfers could be compromised. The existing Table I Transmission System Standards, which have been in place as early as the 1997 NERC Planning Standards, do not allow Loss of Demand or Curtailed Firm Transfers under single (Category B) contingencies. Footnote B addressed two areas: 1) the loss of radial or local network load, which Southern Company agrees that the drafting team has appropriately clarified and 2) preparing for the next contingency, which Southern Company does not agree has been appropriately clarified.Southern Company believes the proposed wording "Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch" now allows for the curtailment of firm transfers for single contingencies, whereas Southern Company did not believe this was previously permitted under the standards. Southern Company interprets the new language to allow a planner to curtail firm transfers (generation) to address a single contingency. Southern Company interpreted the original language to not permit the curtailment of firm transfers (generation) for a single contingency, but rather that a planner would develop a suitable transmission reinforcement or other mitigation. Southern Company is concerned that the proposed language could result in a degradation in the dependability of firm transfers impacting the reliability of those customers who rely upon them. Southern Company agrees that a system reconfiguration including the redispatch of generation is appropriate when preparing for a second contingency (Category C).Therfore, a distinction is needed between what is allowed in response to a first contingency and what is allowed to be prepared for a second contingency. The curtailment of firm transfers should not be allowed as a response to the first contingency. This practice would undermine the concept of firm transfers. The curtailment of firm transfers should only be allowed in footnote b as a system adjustment to be prepared for a second contingency. We propose the following to clarify that curtailments are permitted only to prepare

Organization	Yes or No	Question 1 Comment
		for the second contingency. "To prepare for the next contingency, curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch".
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Orlando Utilities Commission	No	The current language provides a balance between the end goal of reliablity (no load loss for B events) and the practical constraint that project cost may outweigh the benefit. Two things are unclear though. Item one: The standard team should clarify if the bullets under note B are intended to be an AND (both conditions met) or an OR (either condition met). As currently written it is not clear. Item #2: The section under firm transfers is in conflict with the section above. If Demand is being curtailed under the first or second bullet and it's served by firm service then service should also be curtailed, however as written any demand served by firm service could not be curtailed.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Duke Energy	Yes	The effective date in the Implementation Plan needs to be changed to match the Effective Date in the standards, in order to clarify the allowed interruption of Non-consequential load before the new Footnote 'b' takes effect.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Hydro-Quebec Transenergie	Yes	Paragraph should be more clear as:b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances within the planning process, Demand may need to be interrupted to address BES performance requirements. In such case : o Only Interruptible Demand or Demand-Side Management are allowed;o Circumstances where the uses of Demand interruption is needed shall be documented, compared to alternatives, and reviewed in an open and transparent stakeholder process that address stakeholder comments. Curtailment of firm transfers is allowed, when coupled with the appropriate and necessary re-dispatch of resources where it can be demonstrated that this does not result in the shedding of any firm Demand and that Facilities remain within applicable Facility Ratings, including Facilities external to the Transmission Planner's planning region when they are relied upon.
Response: The SDT believes that the changes indicated in your proposed footnote do not add any additional clarity. However, the SDT has reorganized the footnote to clarify its intent.		

Organization	Yes or No	Question 1 Comment
b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~ ~~Interruptible Demand or Demand-Side Management~~ ~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~		
TVA Trasnmission Plannning & Compliance	No	TVA appreciates the SDT's efforts to clarify and improve this complex and challenging area. However, as mentioned in our last comments regarding footnote b, TVA still believes that the SDT's proposal is still focusing more on reliability of local loads than on the overall reliability of the BES. Reliability of local loads should be addressed outside the TPL standards and therefore should not be used/referenced in footnote b. Existing stakeholder processes (referred to in the SDT proposal) typically focus on larger system issues and not on local load serving. TVA believes that some local load should be allowed to be dropped in order to maintain BES reliability. Instead of the proposed footnote b, TVA suggests that the SDT define a "local area" with guidelines detailing the reliability requirements for these local area loads. This would separate the local area load requirements from the BES requirements in the TPL standards.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
New Brunswick System Operator	No	NBSO agrees with the principles of the current version of the proposed footnote, as far as NBSO's interpretation of the footnote is correct. NBSO has the following detailed comments:1. The first paragraph contains many general statements that attempts to capture essential planning principles. NBSO feels that such language is not suited for a footnote. NBSO suggests re-wording of the first paragraph to state:Interruption of Demand may be utilized within the planning process to address BES performance requirements. Such cases are limited to:NBSO also suggests turning the phrase that addresses Demand lost that was served by elements removed from service as a result of a Contingency into a bullet item. NBSO feels

Organization	Yes or No	Question 1 Comment
		that this adds clarity since all of the acceptable instances of Demand interruption are now listed as bulleted items.2. NBSO interprets that the currently proposed footnote allows for the two bulleted options to be used exclusively or in combination. Thus for clarification NBSO suggests adding “or” after each bulleted item, with the exclusion of the final bulleted item.3. NBSO suggests removing the last sentence of the last paragraph. Likely all industry members understand that causing reliability concerns in other areas is never acceptable. This principle is not limited to the standard in question, and thus such a statement could require the update of other standards.4. NBSO interprets that the use of the word “Demand” in the second bullet of the proposed footnote is referring to use of Firm Demand since the first bullet covers the other types of Demand (Demand = Firm Demand + Interruptible Demand). As such NBSO suggests replacing “Demand” with “Firm Demand” in the second bullet.5. NBSO feels that the statement “that includes addressing stakeholder comments” should be removed from the last phrase of the second bullet. An open and transparent stakeholder process should adequately address stakeholder comments and concerns. Explicitly specifying that all stakeholder comments be addressed may add undue burden if the word “address” is misconstrued. The task of addressing stakeholder comments is more appropriately addressed and defined in each area’s respective process.6. NBSO suggests replacing the word “shedding” with “interruption” in the last phrase of the last paragraph to remain consistent with the rest of the proposed footnote. NBSO also suggests capitalizing “firm” in the term “Firm Demand” to remain consistent with the NERC glossary of terms.7. There is no term “transfers” in the NERC glossary of terms. Perhaps some other defined term from the glossary could be used in lieu of “transfers” (e.g. Firm Transmission Service).Taking into account the NBSO comments, the footnote could read as follows:b) Interruption of Demand may be utilized within the planning process to address BES performance requirements. Such cases are limited to:-Demand directly served by Elements removed from service as a result of a Contingency, or-Use of Interruptible Demand or Demand-Side Management, or-Interruption of Firm Demand when acceptable circumstances for such interruptions are documented (including alternatives evaluated), and where the Firm Demand interruption is subject to review in an open and transparent stakeholder process.Curtailment of Firm Transmission Service is allowed when coupled with the appropriate re-dispatch of resources obligated to do so, and it can be demonstrated that Facilities remain within applicable Facility Ratings and there is no additional interruption of Firm Demand.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Manitoba Hydro	No	The last bullet should be made clearer by adding the words “in jurisdictions” before the word “where”. Not all jurisdictions are mandated to have a stakeholder process, so the standard should be clearly written to recognize this situation. "Circumstances where the use of Demand interruption are documented, including alternatives evaluated; and IN JURISDICTIONS where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments."

Organization	Yes or No	Question 1 Comment
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Ameren	No	We agree with the statement that an objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following single contingency events. While we appreciate the drafting team's efforts in removing the need for acceptance by other parties in the stakeholder process, we still feel that language in the second bullet of the revised footnote b should be modified to remove all references to an open and transparent stakeholder process. Existing RTO stakeholder processes that we are aware of focus on larger system issues, rather than on local load serving issues. Therefore, we believe that the load serving issues following single contingency events are issues between the customer and the utility, and should be addressed in one-on-one forums between those entities.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
National Grid	No	National Grid supports the direction the drafting team has taken. However, it has a few concerns with the language of the footnote as amended. 1. Use of the term "Demand": In the first sentence, it is unclear whether the term Demand includes Interruptible Demand and Demand-Side Management. It is suggested that interruption of Demand be clarified to exclude Interruptible Demand or Demand-Side Management. 2. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. 3. National Grid also suggests changing "Demand interruption" to "interruption of Demand" in second bullet under "b)" to avoid awkward and incorrect phasing.4. 'Addressing stakeholder comments' introduces undefined actions which may be required in response to the comments. If 'Demand interruption is subject to review in an open and transparent stakeholder process', then stakeholder comments will be addressed without creating an undefined commitment to require it. As a result, "that includes addressing stakeholder comments" should be deleted. 5. The second paragraph seems to be restricting the use of Demand interruption for the sake of Firm Transfer reduction. This can be stated directly without adding the confusion of re-dispatch. By coupling re-dispatch with a constraint of not shedding Demand, the paragraph also creates confusion as to what to do in a situation where the amount of Demand that is allowed to be shed in the first paragraph could be reduced with re-dispatch. Would re-dispatch not be allowed? National Grid suggests that the paragraph be rewritten as follows: 'Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management).' 6. National Grid seeks clarification if there is an intended distinction between the use of the term "firm Demand" and the defined term "Firm Demand" or is that just a typo?7. The last sentence of footnote B is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own. This same thought would have to be added to multiple

Organization	Yes or No	Question 1 Comment
		NERC standards if it were added here, otherwise it would infer that such actions are acceptable in all other standards.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Northeast Utilities	No	The revised language of Footnote b suggests that non-consequential demand interruption (load that is not directly served by the elements removed from service as a result of the contingency) could be used to mitigate reliability concerns arising from NERC Category B contingency events (i.e., single element contingencies). This language seems to encourage operational workarounds and adds burdens for operators of the system. NU believes this is not consistent with planning a highly reliable bulk electric system and thus does not support this weaker language.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Kansas City Power & Light	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
PacifiCorp	Yes	appreciates the efforts of the SDT and supports revision of TLP-002-0 Table 1 footnote “b” as stated in this draft.
Transmission Strategies, LLC	Yes	
Mohave Electric Cooperative	Yes	
Pepco Holding Inc	Yes	
American Electric Power	Yes	
Georgia Transmission Corporation	Yes	
American Transmission Company	Yes	

Organization	Yes or No	Question 1 Comment
Midwest ISO	Yes	
Independent Electricity System Operator	Yes	
Response: Thank you for your support.		

Consideration of Comments on Successive Ballot — Project 2010-11 – TPL Table 1, Footnote b

Successive Ballot Dates: **12/27/2010 - 1/5/2011**

Summary Consideration:

The SDT reviewed all of the comments received and has made a clarifying change to the structure of the footnote to address industry concerns as to the intent of the SDT. No contextual changes have been made to the footnote. Therefore, the SDT is recommending that this project be moved to a recirculation ballot.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

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]

Balloter	Company	Seg-ment	Vote	Comment
Richard J. Mandes	Alabama Power Company	3	Negative	Southern Company is voting "no" on the footnote b ballot because of concerns that the reliability of firm transfers could be compromised. The existing Table I Transmission System Standards,

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

Balloter	Company	Seg-ment	Vote	Comment
Anthony L Wilson	Georgia Power Company	3	Negative	which have been in place as early as the 1997 NERC Planning Standards, do not allow Loss of Demand or Curtailed Firm Transfers under single (Category B) contingencies. Footnote B addressed two areas: 1) the loss of radial or local network load, which Southern Company agrees that the drafting team has appropriately clarified and 2) preparing for the next contingency, which Southern Company does not agree has been appropriately clarified. Southern Company believes the proposed wording "Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch" now allows for the curtailment of firm transfers for single contingencies, whereas Southern Company did not believe this was previously permitted under the standards. Southern Company interprets the new language to allow a planner to curtail firm transfers (generation) to address a single contingency. Southern Company interpreted the original language to not permit the curtailment of firm transfers (generation) for a single contingency, but rather that a planner would develop a suitable transmission reinforcement or other mitigation. Southern Company is concerned that the proposed language could result in a degradation in the dependability of firm transfers impacting the reliability of those customers who rely upon them. Southern Company agrees that a system reconfiguration including the redispatch of generation is appropriate when preparing for a second contingency (Category C). Therfore, a distinction is needed between what is allowed in response to a first contingency and what is allowed to be prepared for a second contingency. The curtailment of firm transfers should not be allowed as a response to the first contingency. This practice would undermine the concept of firm transfers. The curtailment of firm transfers should only be allowed in footnote b as a system adjustment to be prepared for a second contingency. We propose the following to clarify that curtailments are permitted only to prepare for the second contingency. "To prepare for the next contingency, curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch".
Don Horsley	Mississippi Power	3	Negative	
Horace Stephen Williamson	Southern Company Services, Inc.	1	Negative	

Response: The SDT has changed the wording 'coupled with' to 'achieved through' to better clarify the SDT's intent.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand

Balloter	Company	Seg- ment	Vote	Comment
interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~ As drafted, footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can only be utilized for a limited time, such as a 2 hour emergency rating. It further clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the firm transfers cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the footnote. No change made.				
Jennifer Richardson	Ameren Energy Marketing Co.	6	Negative	We agree with the statement that an objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following single contingency events. While we appreciate the drafting team's efforts in removing the need for acceptance by other parties in the stakeholder process, we still feel that language in the second bullet of the revised footnote b should be modified to remove all references to an open and transparent stakeholder process. Existing RTO stakeholder processes that we are aware of focus on larger system issues, rather than on local load serving issues. Therefore, we believe that the load serving issues following single contingency events are issues between the customer and the utility, and should be addressed in one-on-one forums between those entities.
Kirit S. Shah	Ameren Services	1	Negative	
Response: The SDT disagrees that this should be handled through two party interactions. The SDT believes that in situations where an entity's planning studies require the interruption of Firm Demand to remain within BES Facility Ratings that the entity needs to share those plans in an open and transparent stakeholder process to ensure that other parties that may be impacted by those decisions have the ability to review those plans**.** No change made.				
Steven Norris	APS	3	Negative	It is not clear whether both bullets under "footnote b" have to be met or only one of the two have to be met. It is suggested that the standard be very clear about this
Mel Jensen	APS	5	Negative	
Robert D Smith	Arizona Public Service Co.	1	Negative	
Response: The bullets – o Interruptible Demand or Demand-Side Management and o Circumstances where … are not requirements that must be met, but rather they define the conditions, either one or both, where Load is allowed to be interrupted. The SDT has rearranged the footnote to clarify the intent of the footnote. **b)** An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch,				

Balloter	Company	Seg-ment	Vote	Comment
				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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~ ~~Interruptible Demand or Demand-Side Management~~ ~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~
John Tolo	Tucson Electric Power Co.	1	Negative	The first sentence of the second paragraph appears to conflict with the first paragraph in that it indicates that curtailment of transfers is allowed under certain conditions as long as it doesn't result in the shedding of any firm Demand. Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.
Scott Kinney	Avista Corp.	1	Affirmative	The first sentence of the second paragraph appears to conflict with the first paragraph in that it indicates that curtailment of transfers is allowed under certain conditions as long as it doesn't result in the shedding of any firm Demand. Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.
Robert Lafferty	Avista Corp.	3	Affirmative	
Brenda S. Anderson	Bonneville Power Administration	6	Affirmative	Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.
William Mitchell Chamberlain	California Energy Commission	9	Affirmative	I am voting for this improved standard but I am concerned that the first sentence of the second paragraph appears to conflict with the first paragraph in that it indicates that curtailment of transfers is allowed under certain conditions as long as it doesn't result in the shedding of any firm Demand. This problem could be corrected by adding language to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.

Balloter	Company	Seg-ment	Vote	Comment
Chang G Choi	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	1	Affirmative	Tacoma Power agrees that the revision is better than the existing language. However, to improve clarity on the interrelationship of the 2 paragraphs of Footnote B, we strongly suggest adding the following phrase to the end of the first sentence of the second paragraph, "unless the firm Demand is allowed to be shed pursuant to the above paragraph in this footnote."
Max Emrick	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	5	Affirmative	
James Tucker	Deseret Power	1	Affirmative	As drafted the first paragraph of proposed Footnote B identifies the objective of minimizing interruption of Demand following Contingencies and goes on to identify the limited situation where interruption of demand may be necessary. However, the first sentence of the second paragraph appears to conflict with the first paragraph in that it indicates that curtailment of transfers is allowed under certain conditions as long as it doesn't result in the shedding of any firm Demand. Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed
Chifong L. Thomas	Pacific Gas and Electric Company	1	Affirmative	PG&E supports the proposed footnote B. We believe, however, there is a potential for confusion with the language as currently drafted. As drafted the first paragraph of proposed Footnote B identifies the limited situations where interruption of demand may be necessary and would be allowed. However, the first sentence of the second paragraph indicates that curtailment of transfers is allowed under certain conditions as long as it doesn't result in the shedding of any firm Demand. Taken together with the first paragraph, this requirement can be confusing because the first paragraph potentially conflicts with the second paragraph. Please change the first sentence in the second paragraph to read, "Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand, the interruption of which is otherwise allowed as described above."
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Affirmative	Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.
Travis Metcalfe	Tacoma Public Utilities	3	Affirmative	Tacoma Power agrees that the revision is better than the existing language. However, to improve clarity on the interrelationship of the 2 paragraphs of Footnote B, we strongly suggest adding the following phrase to the end of the first sentence of the second paragraph, "unless the firm Demand is allowed to be shed pursuant to the above paragraph in this footnote."

Balloter	Company	Seg-ment	Vote	Comment
Keith Morisette	Tacoma Public Utilities	4	Affirmative	
Michael C Hill	Tacoma Public Utilities	6	Affirmative	
Beth Young	Tampa Electric Co.	1	Affirmative	Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed
Ronald L Donahey	Tampa Electric Co.	3	Affirmative	
RJames Rocha	Tampa Electric Co.	5	Affirmative	Recommend adding language to paragraph 2, sentence 1 to clarify shedding of firm demand is allowed as stated in Paragraph 1.
Benjamin F Smith II	Tampa Electric Co.	6	Affirmative	
Melissa Kurtz	U.S. Army Corps of Engineers	5	Affirmative	Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.
Brandy A Dunn	Western Area Power Administration	1	Affirmative	As drafted, the first paragraph of proposed Footnote B identifies the objective of minimizing interruption of Demand following Contingencies and goes on to identify the limited situation where interruption of demand may be necessary. However, the first sentence of the second paragraph appears to conflict with the first paragraph in that it indicates that curtailment of transfers is allowed under certain conditions as long as it doesn't result in the shedding of any firm Demand. Western recommends that the Drafting Team include language at the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.

Balloter	Company	Seg-ment	Vote	Comment
Louise McCarren	Western Electricity Coordinating Council	10	Affirmative	WECC supports the concept that is clarified in the proposed language for Footnote B. We have noted however, what could potentially be confusing language between paragraphs one and two of the proposed language. Paragraph one correctly indicates that one of the objectives of transmission planning is to minimize the likelihood and magnitude of interruption of Demand. The first paragraph also recognizes that while this is an objective, there may be certain limited conditions where Demand is interrupted. In recognizing this, the first paragraph lists those limited instances when Demand may be interrupted. However, the first sentence of paragraph two could be interpreted to mean that shedding of Firm Demand is not allowed. The sentence means that shedding of Firm Demand is not allowed due to curtailment of firm transfers, but if there is a situation where curtailment of firm transfers is necessary and curtailment of Demand per the reasons listed in the first paragraph occurs, it should be clear that this is allowed. Suggest adding the following language, or something similar, to the end of the first sentence of the second paragraph of Footnote B. ...except as allowed above.

Response: The SDT has reorganized the footnote to clarify intent and address the issue raised.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~-C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

Balloter	Company	Seg-ment	Vote	Comment
Venkataramakrishnan Vinnakota	BC Hydro	2	Negative	Footnote "b" of TPL-001/2/3/4 is still vague and not acceptable. The last paragraph of Footnote b now reads: "Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected." We would like the SDT to answer the following questions related to the paragraph quoted above: 1) What is meant by "firm transfers"? Is it simply energy flowing in real-time on Firm Transmission Service (NERC defined term) that was not previously curtailed in the hour-ahead or day-ahead scheduling processes, or does it refer to ALL Firm Transmission Service that was sold on a path? 2) Please provide an example of what an "appropriate re-dispatch of resources obligated to re-dispatch" could look like? 3) Assuming an outage of a single transmission line (N-1 Category B event) has occurred and assuming that no "resources [are] obligated to redispatch" for this outage, would a transmission provider be allowed to curtail Firm Transmission Service that it has sold in order to prepare to withstand the next worst credible contingency? 4) Would transmission providers be allowed to sell Firm Transmission Service on a path above what could be delivered with any one element of that path out of service across a range of operating conditions? 5) If the proposed Footnote b is approved, and assuming an appropriate obligation to redispatch could not be negotiated, would utilities have to reinforce their system (within 60 months) to ensure that Firm Transmission Services already sold on particular paths would not be curtailed when any one element of that path is out of service? 6) If a transmission provider employs Generation Dropping for single contingencies in order to support Firm Transmission Service between regions, and assuming there are no provisions for obligated re-dispatch, would the proposed Footnote b force a recalculation of firm vs non-firm transfer capability? 7) Path 66 (PACI) and Path 65 (PDCI) can both see significant derates in their firm transfer capability for single contingencies. How would the proposed Footnote b impact Firm Transmission on these paths? Further, the Project 2010-11 SDT (Footnote "b") should be amalgamated with the Project No. 2006-02 SDT (TPL-001 through TPL004 amalgamation/update): 1. It doesn't make any sense to update Footnote "b" of TPL-001 based on the existing approved

Balloter	Company	Seg-ment	Vote	Comment
				version of TPL-001 when the language in that standard is being revised and terms that Footnote "b" makes reference to will be changed. Draft #6 (2010-Oct-19) of TPL-001 has changed "Footnote b" to "Footnote 9". 2. Draft #6 of TPL-001 has changed the column heading relevant to "Footnote b" from "Loss of Demand or Curtailed Firm Transfers" to "Interruption of Firm Transmission Service Allowed". 3. Draft #6 of TPL-001 has seven new definitions including the following two definitions that would be expected to be relevant to Footnote b: 3.1. Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault. 3.2. Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment. 4. The Project 2006-02 SDT has placed Draft #6 of TPL-001 on hold, stating, "The team will delay moving the standard forward until the resolution of "footnote b" has become clear."
Response: 1. For consistency with the existing standard text, the term 'firm transfer' is retained. Therefore, the interpretation of "firm transfers" remains unchanged. 2. One example would be a contractual arrangement that defines clear expectations to alternately serve Load upon the removal of the firm transfer so that no loss of Load occurs. 3. In the planning timeframe, footnote 'b' addresses single Contingencies (Cat. B) and footnote 'c' addresses the Cat. C Contingencies. Neither footnote prohibits System adjustments, which could include re-dispatch of your own resources to prepare for the next Contingency. 4. How Firm Transmission Service (FTS) is sold is addressed in individual tariffs in concert with the MOD standards. 5. The implementation plan provides 60 months after regulatory approval for entities to comply with the modified standard. How that is accomplished is up to individual entities. 6. & 7 Each circumstance may need to be evaluated individually and additional documentation of understandings may be necessary. 7-1 - 4. Based on ballot comments and regulatory orders, the SDT determined that the best course of action was to address footnote 'b' as a standalone item and then incorporate the changes approved for footnote 'b' into the new TPL-001-2 in a manner consistent with the other proposed changes in TPL-001-2.				
Christopher L de Graffenried	Consolidated Edison Co. of New York	1	Negative	Interruptible Demand, like Demand-Side-Management, is an operational tool. We do not believe it appropriate to use operational tools for transmission planning. A load serving entity should not claim to serve loads it plans to disconnect during a design contingency. In other words, these loads should be excluded from the load forecast in the first place and, thereby, would not be represented in power flows that are utilized to assess system performance under the TPL standards. This approach prevents the use of such load interruptions to address any deficiency found in TPL-type
Peter T Yost	Consolidated Edison Co. of New York	3	Negative	

Balloter	Company	Seg-ment	Vote	Comment
Wilket (Jack) Ng	Consolidated Edison Co. of New York	5	Negative	assessments.
Nickesha P Carrol	Consolidated Edison Co. of New York	6	Negative	
Response: Entities across the continent have many different Interruptible and Demand-Side Management programs that have many different attributes and rules. Some entities have Interruptible Demand programs that are appropriate for planning purposes.				
Chuck B Manning	Electric Reliability Council of Texas, Inc.	2	Negative	The introductory paragraph of footnote b includes policy language. Since this is a reliability standard-and not a policy directive-the general narrative setting forth the desired policy goal of minimizing load-shedding is misplaced. Including policy language can cloud the specific issues the standard attempts to address, and ERCOT recommends deleting the first two sentences in the introductory paragraph. The next sentence in the introductory paragraph goes on to state, generally, that demand may be interrupted to "address BES performance requirements." This phrase is vague. To which performance requirements does this refer? The intent is not clear. If the intent is to generally recognize the need to shed load to respect to NERC standards and to allow flexibility for an entity to exercise discretion relative to meeting BES performance requirements, then that intent should be clearly reflected in the language. Furthermore, the last sentence of the introductory paragraph and the subsequent bullet points are arguably inconsistent with this approach, because they could be viewed as removing an entity's flexibility/discretion by limiting the circumstances when load can be shed. The second bullet point is unnecessary, because it is already apparent that interruptible demand/demand side management programs can be used according to their terms. This could create confusion in that it could be implied that, absent the need to use these to meet BES performance requirements, using them otherwise is inconsistent with/not allowed under footnote b. Simply put, those products are not load shedding as contemplated by this footnote. Therefore they should not be listed here. With respect to the third bullet point, the phrase "demand that does not adversely impact overall BES reliability" is not adequately defined, and provides opportunity for confusion. This is an ambiguous phrase and can't be linked back to objective NERC standards/requirements. The bullet points should avoid ambiguity to mitigate ambiguity risk in audits.

Balloter	Company	Seg-ment	Vote	Comment
				In addition, the last part of the language in this bullet imposing an open and transparent stakeholder process is unclear. What is the intent behind requiring review in a stakeholder process? If it is to establish the ability of the entity to develop load shedding procedures beyond those explicitly contemplated in footnote b, ERCOT questions if it is reasonable for the responsible entity to be required to get "permission" from stakeholders to implement reliability measures related to its obligation as the functional entity. Again, the language simply is not clear. Accordingly, ERCOT recommends this bullet point be removed. If it is retained, it should be revised consistent with these comments to remove ambiguous language to mitigate potential confusion around the meaning/scope of the footnote in the administration of the CMEP. In addition, ERCOT recommends revising the draft footnote b to allow for planned Demand interruption as a means of mitigation during interim periods when a unanticipated (such as unexpected demand growth or unit retirements) or temporary change on the system occurs in a timeframe that is shorter than the time necessary to plan and implement the system upgrades necessary to avoid the Demand interruption. Finally, in the last paragraph of footnote b, it isn't clear why "Transmission Service" was changed to "transfers." Firm transmission service is a service provided in some regions, and it provides relative value to other types of services-e.g., non-firm and network. The mention of transmission service may also be irrelevant in this footnote, since the allowance of its interruption doesn't also allow for load shedding. Therefore, ERCOT recommends eliminating the last paragraph of footnote b.

Response: The SDT believes that the first part of the footnote is necessary to provide context for the items that follow and has crafted the language to provide a balance between flexibility and consistency across NERC. No change made.

The term "BES performance requirements" references the other requirements within the TPL standard and the SDT has removed the phrase "demand that does not adversely impact overall BES reliability".

In a previous posting, entities had stated that it was not clear that the use of Interruptible Load and Demand Side Management was permitted. The SDT added this section to address those concerns. The SDT has reorganized and reformatted the footnote to improve clarity.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm

Balloter	Company	Seg-ment	Vote	Comment
Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~ ~~Interruptible Demand or Demand-Side Management~~ ~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~ The open and transparent process does not require "permission", but rather it facilitates the open sharing of information between entities that have responsibility for ensuring BES reliability. The SDT decided to not limit the use of the footnote to a specific time period because there are circumstances where the longer term use may be implemented without adversely impacting BES reliability. For consistency with the existing standard text, the term 'firm transfer' is retained. No change made.				
Claudiu Cadar	GDS Associates, Inc.	1	Negative	We appreciate all the work conducted by SDT to adjust current footnote "b" however, we disagree with the current approach mainly from the same reasons iterated during last comment period, as follows: • The definition does not go far enough with recognition that interruption of Demand should be mitigated if at all possible. The language should encourage the TP to develop mitigation plans that could be implemented as an alternative to Demand interruption. • Use of Interruptible Demand should only be implemented if the Transmission Planner can point to a contract between the Transmission Provider and Transmission Customer that permits load curtailment. • Under FERC Order 890, Conditional Firm transmission service can be granted for entities who voluntarily acknowledge the right of the Transmission Provider to curtail their transaction or provide re-dispatch. This should be the only transfer which can be utilized in the Planning Horizon for interruption of Demand for Note b. We suggest using the following wording as emphasized below: "An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events and to develop mitigation plans that do not call for the curtailment of Demand.

Balloter	Company	Seg-ment	Vote	Comment
				It is recognized that Demand will be interrupted if it is directly served by the elements removed from service as a result of the Contingency and in very limited circumstances when approaching intermediate solutions to restore BES reliability. When interruption of Demand is utilized within the planning process, such interruption is limited to: ? Demand that is directly served by the elements that are removed from service as a result of the Contingency, ? Interruptible Demand or Demand-Side Management, where the Customer has given explicit rights to the Transmission Provider for curtailment of their Demand, ? Demand, other than Interruptible Demand or Demand-Side Management, that does not adversely impact overall BES reliability where the circumstances describing the use of such Demand are documented, including alternatives evaluated; where the Load-Serving Entity who has responsibility for serving such Demand has agreed to the curtailment, and where the application is subject to review and acceptance in an open and transparent stakeholder process. Curtailment of Firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch per the terms and conditions of the confirmed transmission service request between the Transmission Customer and Transmission Provider, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected. In addition, any Conditional Firm transfers may be curtailed, in accordance with the terms and conditions of the confirmed transmission service request between the Transmission Customer and Transmission Provider."
Response: In the footnote, the SDT has acknowledged that interrupting Firm Demand is not the preferred solution to BES concerns, while recognizing that this may not always be possible. The SDT believes that the footnote as drafted strikes an appropriate balance. No change made. It is well understood that there must be some agreement or contract before interruptible Demand or Demand-Side Management can be utilized by the planner. The SDT disagrees that there should be a prohibition on utilizing other resources obligated to re-dispatch for Contingencies, unless it has been characterized as "conditional firm". Entities should not be restricted from utilizing other dispatch scenarios, as long as Firm Demand is not interrupted. For the reasons stated above, the SDT has not modified the footnote as suggested.				
Joe D Petaski	Manitoba Hydro	1	Negative	The last bullet should be made clearer by adding the words "in jurisdictions" before the word "where". Not all jurisdictions are mandated to have a stakeholder process, so the standard should be clearly written to recognize this situation. "Circumstances where the use of Demand interruption are documented, including alternatives evaluated; and IN JURISDICTIONS where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments."
Greg C. Parent	Manitoba Hydro	3	Negative	
S N Fernando	Manitoba Hydro	5	Negative	
Daniel	Manitoba Hydro	6	Negative	

Balloter	Company	Segment	Vote	Comment
Prowse				
Response: The SDT believes that if Firm Demand is planned to be interrupted utilizing footnote 'b', there must be an open and transparent stakeholder process to ensure that all parties that may be impacted have been notified and have an opportunity to provide comments. No change made.				
Spencer Tacke	Modesto Irrigation District	4	Negative	I am voting NO on the proposed revision because the second bullet of the proposed revision is nebulous as to how the exemption process will occur, and how it will be monitored by the auditors. Also, the last sentence of the last paragraph of the proposed change is nebulous about keeping facility flows within applicable Normal and Emergency thermal ratings. Thank you.
Response: Rather than mandate a one-size-fits-all process, the SDT has provided entities the latitude to utilize existing processes, modify existing processes, or create new processes to provide an open and transparent stakeholder process. The SDT cannot comment on future actions of the auditors. The SDT disagrees that maintaining Facilities within applicable Facility Ratings is a nebulous concept. That part of the footnote was included to ensure that the plans to resolve a situation on a planner's System did not create other overloads. No change made.				
Saurabh Saksena	National Grid	1	Negative	National Grid supports the direction the drafting team has taken. However, it has a few concerns with the language of the footnote as amended. 1. Use of the term "Demand": In the first sentence, it is unclear whether the term Demand includes Interruptible Demand and Demand-Side Management. It is suggested that interruption of Demand be clarified to exclude Interruptible Demand or Demand-Side Management. 2. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet.

Balloter	Company	Seg-ment	Vote	Comment
Michael Schiavone	Niagara Mohawk (National Grid Company)	3	Negative	3. National Grid also suggests changing "Demand interruption" to "interruption of Demand" in second bullet under "b)" to avoid awkward and incorrect phasing. 4. 'Addressing stakeholder comments' introduces undefined actions which may be required in response to the comments. If 'Demand interruption is subject to review in an open and transparent stakeholder process', then stakeholder comments will be addressed without creating an undefined commitment to require it. As a result, "that includes addressing stakeholder comments" should be deleted. 5. The second paragraph seems to be restricting the use of Demand interruption for the sake of Firm Transfer reduction. This can be stated directly without adding the confusion of re-dispatch. By coupling re-dispatch with a constraint of not shedding Demand, the paragraph also creates confusion as to what to do in a situation where the amount of Demand that is allowed to be shed in the first paragraph could be reduced with re-dispatch. Would re-dispatch not be allowed? National Grid suggests that the paragraph be rewritten as follows: 'Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management).' 6. National Grid seeks clarification if there is an intended distinction between the use of the term "firm Demand" and the defined term "Firm Demand" or is that just a typo? 7. The last sentence of footnote B is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own. This same thought would have to be added to multiple NERC standards if it were added here, otherwise it would infer that such actions are acceptable in all other standards.

Response: 1. The SDT has reorganized the text in the footnote to address this concern.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

Balloter	Company	Seg-ment	Vote	Comment
~~Interruptible Demand or Demand Side Management~~ ~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~ **2.** The SDT has reorganized the text in the footnote to address this concern. **3.** The SDT believes that the proposed change does not add additional clarity to the footnote. No change made. **4.** The SDT disagrees that each review process automatically will have a response to comments element. Therefore, the SDT added that element to ensure that all stakeholder processes will include that element. No change made. **5.** The SDT has reorganized the text in the footnote to address this concern. **6.** The SDT has corrected the capitalization errors. **7.** Since the planned action of curtailing of firm transfers may adversely impact neighboring systems, the SDT believes that it is important in this situation to articulate a condition that is normally implied. The SDT disagrees that an explicit statement in this footnote changes the intent of all other standards. No change made.				
Tony Eddleman	Nebraska Public Power District	3	Negative	NPPD votes NO due to the ambiguity of the terms "Curtailment of firm transfers is allowed, when coupled the appropriate re-dispatch of resources" with respect to a Category B contingency event. NPPD does not support the curtailment of firm transfers or re-dispatch to meet the performance requirements during a Category B (N-1) event. Curtailment of firm transfers and re-dispatch are allowable following acceptable performance for the Category B (N-1) event, to get ready for the next Category C type of event.
Don Schmit	Nebraska Public Power District	5	Negative	
Response: As drafted, footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can only be utilized for a limited time, such as a 2 hour emergency rating. It further clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the firm transfers cannot be curtailed. No change made.				

Balloter	Company	Seg-ment	Vote	Comment
Randy MacDonald	New Brunswick Power Transmission Corporation	1	Negative	In general: NERC standards should not dictate circumstances or acceptable transmission contingencies under which the tripping of customers loads is acceptable. That should be an issue between the utility of supply, the customer, and the local regulating body so long as the interruption to customers (for whatever contingency) is controlled and does not cause problems on the BES, or to neighboring utilities. Specifically, 1. The second bullet: The last sentence (following the semicolon) should be removed. The local regulating body should provide input or approval. 2. NB Power Transmission interprets that the currently proposed footnote allows for the two bulleted options to be used exclusively or in combination. Thus for clarification suggest adding "or" after the first bulleted item.

Response: The SDT disagrees that this should be handled exclusively with the local regulating body. The SDT believes that in situations where an entity's planning studies require the interruption of Firm Demand to remain within BES Facility Ratings that the entity needs to share those plans in an open and transparent stakeholder process to ensure that other parties that may be adversely impacted by those decisions have the ability to review those plans**.** No change made.

The SDT has reorganized the footnote to clarify its intent and address the issue raised.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

Balloter	Company	Seg-ment	Vote	Comment
Alden Briggs	New Brunswick System Operator	2	Negative	NBSO agrees with the principles of the current version of the proposed footnote assuming NBSO's interpretation of the footnote is correct. NBSO has the following detailed comments: 1. The first paragraph contains many general statements that attempts to capture essential planning principles. NBSO feels that such language is not suited for a footnote. NBSO suggests re-wording of the first paragraph to state: Interruption of Demand may be utilized within the planning process to address BES performance requirements. Such cases are limited to: NBSO also suggests turning the phrase that addresses Demand lost that was served by elements removed from service as a result of a Contingency into a bullet item. NBSO feels that this adds clarity since all of the acceptable instances of Demand interruption are now listed as bulleted items. 2. NBSO interprets that the currently proposed footnote allows for the two bulleted options to be used exclusively or in combination. Thus for clarification NBSO suggests adding "or" after each bulleted item, with the exclusion of the final bulleted item. 3. NBSO suggests removing the last sentence of the last paragraph. Likely all industry members understand that causing reliability concerns in other areas is never acceptable. This principle is not limited to the standard in question, and thus such a statement could require the update of other standards. 4. NBSO interprets that the use of the word "Demand" in the second bullet of the proposed footnote is referring to use of Firm Demand since the first bullet covers the other types of Demand (Demand = Firm Demand + Interruptible Demand). As such NBSO suggests replacing "Demand" with "Firm Demand" in the second bullet. 5. NBSO feels that the statement "that includes addressing stakeholder comments" should be removed from the last phrase of the second bullet. An open and transparent stakeholder process should adequately address stakeholder comments and concerns. Explicitly specifying that all stakeholder comments be addressed may add undue burden if the word "address" is misconstrued. The task of addressing stakeholder comments is more appropriately addressed and defined in each area's respective process. 6. NBSO suggests replacing the word "shedding" with "interruption" in the last phrase of the last paragraph to remain consistent with the rest of the proposed footnote. NBSO also suggests capitalizing "firm" in the term "Firm Demand" to remain consistent with the NERC glossary of terms.

Balloter	Company	Seg-ment	Vote	Comment
				7. There is no term "transfers" in the NERC glossary of terms. Perhaps some other defined term from the glossary could be used in lieu of "transfers" (e.g. Firm Transmission Service). Taking into account the NBSO comments, the footnote could read as follows: b) Interruption of Demand may be utilized within the planning process to address BES performance requirements. Such cases are limited to: -Demand directly served by Elements removed from service as a result of a Contingency, or -Use of Interruptible Demand or Demand-Side Management, or -Interruption of Firm Demand when acceptable circumstances for such interruptions are documented (including alternatives evaluated), and where the Firm Demand interruption is subject to review in an open and transparent stakeholder process. Curtailment of Firm Transmission Service is allowed when coupled with the appropriate re-dispatch of resources obligated to do so, and it can be demonstrated that Facilities remain within applicable Facility Ratings and there is no additional interruption of Firm Demand.

Response: **1 & 2.** The SDT believes that the first part of the footnote is necessary to provide context for the items that follow and has crafted the language to provide a balance between flexibility and consistency across NERC. The SDT has reorganized the footnote to clarify its intent and address the issue raised.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

3. Since the planned action of curtailing of firm transfers may adversely impact neighboring Systems, the SDT believes that it is important in this situation to articulate a condition that is normally implied. The SDT disagrees that an explicit statement in this footnote changes the intent of all other standards.
4. The SDT has reorganized the footnote to clarify its intent and address the issue raised.
5. The SDT believes that in situations where an entity's planning studies require the interruption of Firm Demand to remain within BES Facility Ratings that the

Balloter	Company	Seg-ment	Vote	Comment
entity needs to share those plans in an open and transparent stakeholder process to ensure that other parties that may be adversely impacted by those decisions have the ability to review those plans. No change made. **6.** The SDT does not believe that replacing the term shedding with interruption adds clarity and did not make the proposed change. The SDT has reorganized the footnote to clarify its intent and address the second issue. **7.** For consistency with the existing standard text, the term 'firm transfer' is retained. No change made.				
David H. Boguslawski	Northeast Utilities	1	Negative	The revised language of Footnote b suggests that non-consequential demand interruption (load that is not directly served by the elements removed from service as a result of the contingency) could be used to mitigate reliability concerns arising from NERC Category B contingency events (i.e., single element contingencies). This language seems to encourage operational workarounds and adds burdens for operators of the system. NU believes this is not consistent with planning a highly reliable bulk electric system and thus does not support this weaker language.
Response: The SDT believes that the language in this footnote is not weaker and does not encourage operational workarounds. The footnote language provides the framework necessary to ensure that in situations where an entity's planning studies require the interruption of Firm Demand to remain within BES Facility Ratings that the entity needs to share those plans in an open and transparent stakeholder process to ensure that other parties that may be adversely impacted by those decisions have the ability to review those plans. No change made.				
Brad Chase	Orlando Utilities Commission	1	Negative	"Two Items prevent us from voting yes. Item #1: The standard team should clarify if the bullets under note B are intended to be an AND (both conditions met) or an OR (either condition met). As currently written it is not clear. Item #2: The section under firm transfers is in conflict with the section above. If Demand is being curtailed under the first or second bullet and it's served by firm service then service should also be curtailed, however as written any demand served by firm service could not be curtailed. Other then these items the revisions does an excellent job of addressing the issue of load shedding under first contingency conditions and practical reliablity."
Ballard Keith Mutters	Orlando Utilities Commission	3	Negative	
Response: The SDT has reorganized the footnote to clarify its intent and address this issue. b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~ ~~Interruptible Demand or Demand-Side Management~~				

Balloter	Company	Seg-ment	Vote	Comment
~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~				
Linda Brown	San Diego Gas & Electric	1	Negative	Footnote b is a group of exceptions to the requirements for Category B contingencies. To add clarity to the footnote, SDG&E would prefer that each exception be listed separately within the footnote. As SDG&E understands the footnote, the following exceptions can occur after the loss of a single element, • Interruptible Demand can be used to unload a circuit, but the circuit(s) must remain below emergency rating(s) at all times. • Demand-Side Management can be used to unload a circuit, but the circuit(s) must remain below emergency rating(s) at all times. • Demand served by a radial element which is faulted may be interrupted. • Curtailment of firm transfers is allowed, when coupled with re-dispatch of resources obligated to re-dispatch. SDG&E votes against the proposed language for the following reasons: SDG&E feels system reliability alone should drive the need for a technical standard and the language of the standard should reflect the need without reference to the process. FERC Order 890 set the forum for the stakeholder process which provides commercial incentives and a level playing field for any participant to build a transmission project. When considering compliance to the standards, reference to "stakeholder process" is inappropriate and should be removed. Section 4 of the TPL standards assigns responsibility for meeting the standards to the Planning Authority and the Transmission Planner. These entities are subject to penalties if the requirement is not met. Use of "stakeholder process" in the requirement implies that entities other than the Planning Authority or the Transmission Planner have authority over how the standards are to be met without any financial risk. If the "stakeholder process" language is not removed, SDG&E feels stakeholders involved in the process should be registered with NERC and subject to the same audit requirements and penalties as the Planning Authority or the Transmission Planner. Furthermore, the California Transmission Owners have a FERC approved stakeholder process that is administered by the California ISO. Addition of the term "stakeholder process" in a standard may have unintended consequences.

<table>
<tr><th>Balloter</th><th>Company</th><th>Seg-ment</th><th>Vote</th><th>Comment</th></tr>
<tr><td colspan="5">Response: While the SDT believes that SDG&E proposed bullet list is consistent with the footnote as drafted, the list is not as inclusive as the footnote. Therefore, the SDT has retained the existing text and reorganized the footnote for clarity.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~-C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected.~~

The SDT believes that in situations where an entity’s planning studies require the interruption of Firm Demand to remain within BES Facility Ratings that the entity needs to share those plans in an open and transparent stakeholder process to ensure that other parties that may be adversely impacted by those decisions have the ability to review those plans. No change made.</td></tr>
<tr><td>Charles H Yeung</td><td>Southwest Power Pool</td><td>2</td><td>Negative</td><td>The second paragraph of the footnote seems to be restricting the use of Demand interruption for the sake of Firm Transfer reduction. This can be stated directly without adding the confusion of re-dispatch. By coupling re-dispatch with a constraint of not shedding Demand, the paragraph also creates confusion as to what to do in a situation where the amount of Demand that is allowed to be shed in the first paragraph could be reduced with re-dispatch. Would re-dispatch not be allowed? We suggest that the paragraph be rewritten as follows: “Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management).”</td></tr>
<tr><td colspan="5">Response: The SDT has reorganized the footnote to clarify its intent and address this issue.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch,</td></tr>
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Balloter	Company	Seg-ment	Vote	Comment
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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~ ~~Interruptible Demand or Demand-Side Management~~ ~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~				
Larry Akens	Tennessee Valley Authority	1	Negative	TVA appreciates the SDT's efforts to clarify and improve this complex and challenging area. However, as mentioned in our last comments regarding footnote b, TVA still believes that the SDT's proposal is still focusing more on reliability of local loads than on the overall reliability of the BES. Reliability of local loads should be addressed outside the TPL standards and therefore should not be used/referenced in footnote b. Existing stakeholder processes (referred to in the SDT proposal) typically focus on larger system issues and not on local load serving. TVA believes that some local load should be allowed to be dropped in order to maintain BES reliability. Instead of the proposed footnote b, TVA suggests that the SDT define a "local area" with guidelines detailing the reliability requirements for these local area loads. This would separate the local area load requirements from the BES requirements in the TPL standards.
Ian S Grant	Tennessee Valley Authority	3	Negative	
George T. Ballew	Tennessee Valley Authority	5	Negative	
Marjorie S. Parsons	Tennessee Valley Authority	6	Negative	
Response: The original footnote 'b' focused on local area and limited interruption of Demand. Since individual entities planning philosophies are different across North America, the SDT has been unable to determine a one-size-fits-all definition for local area. Therefore, the SDT adopted an approach that allows entities to utilize input from stakeholders in an open and transparent process. In this way, any affected party has a mechanism to ensure that the planners are planning a reliable BES. No change made.				
Pat G. Harrington	BC Hydro and Power Authority	3	Negative	
Gordon Rawlings	BC Transmission Corporation	1	Negative	
Response: With no comment provided, the SDT is unable to provide a response.				
Gregg R Griffin	City of Green Cove Springs	3	Affirmative	An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will

Balloter	Company	Seg-ment	Vote	Comment
				be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: Interruptible Demand or Demand-Side Management Circumstances where the uses of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.
Response: Thank you for your support.				
Guy V. Zito	Northeast Power Coordinating Council, Inc.	10	Affirmative	1. There is concern with the use of the term Demand. It is unclear throughout the footnote whether or not the term Demand includes Interruptible Demand or Demand-Side Management. It is suggested that interruption of Demand be clarified to not include Interruptible Demand or Demand-Side Management to more clearly show the permitted use of Load shedding. 2. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. 3. Language that mitigation of Load and/or Demand interruption should be pursued within the planning process should be reinstated as reinforcement of a Transmission Providers' planning obligations to their load customers, and system operations. 4. Footnote 'b' should be made to read as follows: b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of Load and/or Demand following Contingency events. Interruption of Load and/or Demand is discouraged and all measures to mitigate such interruption should be pursued within the planning process. However, it is recognized that Load and/or Demand will be interrupted if it is directly served by the elements automatically removed from service by the Protection System as a result of a Contingency. Furthermore, in extraordinary circumstances within the planning process Load and/or Demand may need to be interrupted to address BES performance requirements. When interruption of Load and/or Demand is utilized within the planning

Balloter	Company	Seg-ment	Vote	Comment
				process to address BES performance requirements, such interruption is limited to: • Circumstances where the use of Load and/or Demand interruption are documented, including alternatives evaluated; and where the Load and/or Demand interruption is made available for review in an open and transparent stakeholder process. If Load and/or Demand interruption is necessary, planning should indicate the amount needed, and not specify how it would be obtained. What Load and/or Demand is interrupted is an operational decision. 5. Additional comments not included in the material listed for footnote 'b' on the Comment Form. In the paragraph below the bullets in footnote 'b', confusion is introduced through the use of the term "firm Demand". It is unclear how this is different than the defined term "Firm Demand" and what the implications of the term "firm Demand" are. This footnote should not discourage such adjustments which actually increase the reliability of service to end users. 6. The last sentence of footnote 'b' is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own.

Response: 1. The SDT has reorganized the footnote to clarify its intent and address this issue.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~-C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

2. The SDT has reorganized the footnote to clarify its intent and address the issue raised.

Balloter	Company	Seg-ment	Vote	Comment
3. & 4. The SDT addressed these concerns by including the phrase "including alternatives evaluated" and does not believe that it is appropriate to dictate that the planners must evaluate "all measures to mitigate" annually or the specific details concerning documentation of alternatives. **5.** The SDT has corrected the capitalization errors. **6.** Since the planned action of curtailing of firm transfers may adversely impact neighboring systems, the SDT believes that it is important in this situation to articulate a condition that is normally implied. No change made.				
Ajay Garg	Hydro One Networks, Inc.	1	Affirmative	Hydro One is casting an affirmative vote on the revisions to Table 1, footnote 'b' in TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. However, we believe the proposed language might be confusing and should be modified to read as follows: "b) It is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Interruptible Demand or Demand-Side Management o Circumstances where the uses of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the interruption of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected." Note that the voting system does not permit to enter re-lined comments. We can provide a red-lined document with our proposal upon request.
David L Kiguel	Hydro One Networks, Inc.	3	Affirmative	

Response: The SDT believes that the sentences deleted in your proposed footnote are necessary to provide context for the items that follow and has crafted the language to provide a balance between flexibility and consistency across NERC. The SDT has reorganized the footnote to clarify its intent.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

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Balloter	Company	Seg-ment	Vote	Comment
~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~				
Henry Ernst-Jr	Duke Energy Carolina	3	Affirmative	The effective date in the Implementation Plan needs to be changed to match the Effective Date in the standards, in order to clarify the allowed interruption of Non-consequential load before the new Footnote 'b' takes effect.
Response: The effective dates in the Implementation Plan match those in the standards. No change made.				
Mark B Thompson	Alberta Electric System Operator	2	Abstain	While the AESO does not generally disagree with the intent of the proposed change, we have voted "abstain". In particular, as reflected in the adopted Alberta Reliability Standard TPL-002-AB-0, no loss of Demand and Generation have been given equal consideration for Category B contingencies. In addition, within the Alberta energy market structure and the operation of the transmission system, there are no firm transfers on transmission facilities in Alberta.
Response: Individual jurisdictions are allowed to have more restrictive standards and therefore, this revision to the standard does not dictate that a jurisdiction must change its requirements. The SDT recognizes that there may be areas or markets that do not utilize terms contained within the standard.				

Exhibit D

Record of Development of Proposed Reliability Standards

Project 2010-11
TPL Table 1 Order

Related Files

Status:
Approved by the Board of Trustees on February 17, 2011.

Purpose / Industry Need:
The SAR is to address FERC Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote ‘b’, regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system by June 30, 2010. The SAR provides a revision to TPL Table 1 footnote ‘b’ to provide clarity to industry with regard to the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. The referenced table appears in TPL-001, TPL-002, TPL-003, and TPL-004 so while the FERC Order was for TPL-002, the change is reflected in all 4 standards.

Draft	Action	Dates	Results	Consideration of Comments
Implementation Plan(67) **TPL-001-1** Clean(64) | Redline to last posting(65) Redline to last approval(66) **TPL-002-1b** Clean(61) | Redline to last posting(62) Redline to last approval(63) **TPL-003-1a** Clean(58) | Redline to last posting(59) Redline to last approval(60) **TPL-004-1** Clean(55) | Redline to last posting(56) Redline to last approval(57)	Recirculation Ballot Info(68) Vote>>	01/26/11 – 02/05/11 (closed)	Summary(70) Full Record(69)	
	Initial Ballot	12/27/10 - 01/05/11	Summary(53) Full	Consideration of Comments(54)

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TPL-001-1

Clean(43) | Redline to last posting(44)

Redline to last approval(45)

TPL-002-1b

Clean(40) | Redline to last posting(41)

Redline to last approval(42)

TPL-003-1a

Clean(37) | Redline to last posting(38)

Redline to last approval(39)

TPL-004-1

Clean(34) | Redline to last posting(35)

Redline to last approval(36)

Supporting Materials:
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Clean(27) | Redline to last posting(28)

TPL-002-1b
Clean(25) | Redline to last posting(26)

TPL-003-1a
Clean(23) | Redline to last posting(24)

TPL-004-1
Clean(21) | Redline to last posting(22)

Supporting Materials:
Comment Form (Word)(20)</td>
<td>Comment Period

Submit Comments>>
| Info(30)</td>
<td>09/08/10
-
10/08/10
(closed)</td>
<td>Comments Received(31)</td>
<td>Comment Report(32)</td>
</tr>
</table>

SAR(11) Implementation Plan(10) TPL-001-1 Clean(8) | Redline to last approval(9) TPL-002-1b Clean(6) | Redline to last approval(7) TPL-003-1a Clean(4) | Redline to last approval(5) TPL-004-1 Clean(2) | Redline to last approval(3) **Supporting Materials:** Comment Form (Word)(1)	Initial Ballot Vote>> | Info(16)	05/17/10 - 05/27/10 (closed)	Summary(18) Full Record(17)	Comment Report(19)
	Pre-ballot Review Join>> | Info(15)	04/15/10 - 05/17/10 (closed)		
	Comment Period Submit Comments>> | Info>>(12)	04/15/10 - 05/26/10 (closed)	Comments Received(13)	Comment Report(14)

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RELIABILITY CORPORATION

Unofficial Comment Form for SAR for Project 2010-11: TPL Table 1 Order

Please **DO NOT** use this form to submit comments. Please the electronic form located at the link below to submit comments on the SAR for Project 2010-11: TPL Table 1 Order. This comment form must be completed by **May 25, 2010.**

If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Background Information

The SAR is to address FERC Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system by June 30, 2010.

The SAR provides a revision to TPL Table 1 footnote 'b' to provide clarity to industry with regard to the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. The referenced table appears in TPL-001, TPL-002, TPL-003, and TPL-004 so while the FERC Order was for TPL-002, the change is reflected in all 4 standards.

1. The SDT is proposing a revision to footnote 'b' in the TPL tables to comply with FERC Order RM-06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system by June 30, 2010. Do you agree with the proposed changes and if not, please provide specific reasons for your disagreement.

   ☐ Yes
   ☐ No
   Comments:

2. Are you aware of any conflicts caused by compliance with the proposed language in Table 1 — footnote b and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement? If yes, please identify the conflict.

   ☐ Yes
   ☐ No
   Comments:

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. None.

Proposed Action Plan and Description of Current Draft:

The SDT has submitted a SAR to address FERC Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System by June 30, 2010. Due to the timeframe involved, the SDT has requested an Urgent Action process be approved by the Standards Committee. To accommodate this process, the SDT has supplied drafts of the affected TPL standards as part of the SAR submittal.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit SAR to SC	April 2010
2. Approval of SAR by SC	April 2010
3. 30 day pre-ballot period	April – May 2010
4. Initial ballot	May 2010
5. Recirculation ballot	June 2010
6. Submit to BOT for approval	June 2010
7. File with FERC	June 2010

A. Introduction

1. Title: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. Number: TPL-004-1

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-1_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-1_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

<table>
<tr><th rowspan="2">Category</th><th>Contingencies</th><th colspan="3">System Limits or Impacts</th></tr>
<tr><th>Initiating Event(s) and Contingency Element(s)</th><th>System Stable and both Thermal and Voltage Limits within Applicable Rating [a]</th><th>Loss of Demand or Curtailed Firm Transfers</th><th>Cascading Outages</th></tr>
<tr><td>A
No Contingencies</td><td>All Facilities in Service</td><td>Yes</td><td>No</td><td>No</td></tr>
<tr><td rowspan="2">B
Event resulting in the loss of a single element.</td><td>Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:
1. Generator
2. Transmission Circuit
3. Transformer
Loss of an Element without a Fault.</td><td>Yes
Yes
Yes
Yes</td><td>No [b]
No [b]
No [b]
No [b]</td><td>No
No
No
No</td></tr>
<tr><td>Single Pole Block, Normal Clearing[e]:
4. Single Pole (dc) Line</td><td>Yes</td><td>No[b]</td><td>No</td></tr>
<tr><td rowspan="5">C
Event(s) resulting in the loss of two or more (multiple) elements.</td><td>SLG Fault, with Normal Clearing[e]:
1. Bus Section
2. Breaker (failure or internal Fault)</td><td>Yes
Yes</td><td>Planned/ Controlled[c]
Planned/ Controlled[c]</td><td>No
No</td></tr>
<tr><td>SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]:
3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency</td><td>Yes</td><td>Planned/ Controlled[c]</td><td>No</td></tr>
<tr><td>Bipolar Block, with Normal Clearing[e]:
4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]:
5. Any two circuits of a multiple circuit towerline[f]</td><td>Yes
Yes</td><td>Planned/ Controlled[c]
Planned/ Controlled[c]</td><td>No
No</td></tr>
<tr><td>SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure):
6. Generator
7. Transformer
8. Transmission Circuit
9. Bus Section</td><td>Yes
Yes
Yes
Yes</td><td>Planned/ Controlled[c]
Planned/ Controlled[c]
Planned/ Controlled[c]
Planned/ Controlled[c]</td><td>No
No
No
No</td></tr>
</table>

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

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. None.

Proposed Action Plan and Description of Current Draft:

The SDT has submitted a SAR to address FERC Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System by June 30, 2010. Due to the timeframe involved, the SDT has requested an Urgent Action process be approved by the Standards Committee. To accommodate this process, the SDT has supplied drafts of the affected TPL standards as part of the SAR submittal.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit SAR to SC	April 2010
2. Approval of SAR by SC	April 2010
3. 30 day pre-ballot period	April – May 2010
4. Initial ballot	May 2010
5. Recirculation ballot	June 2010
6. Submit to BOT for approval	June 2010
7. File with FERC	June 2010

A. Introduction

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)
2. **Number**: TPL-004-~~0a~~ 1
3. **Purpose**: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
4. **Applicability**:
   - **4.1.** Planning Authority
   - **4.2.** Transmission Planner
5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective~~April 1, 2005~~

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-~~0~~1_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-~~0~~1_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) ~~Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~ No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

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. None.

Proposed Action Plan and Description of Current Draft:

The SDT has submitted a SAR to address FERC Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System by June 30, 2010. Due to the timeframe involved, the SDT has requested an Urgent Action process be approved by the Standards Committee. To accommodate this process, the SDT has supplied drafts of the affected TPL standards as part of the SAR submittal.

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Anticipated Actions	Anticipated Date
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2. Approval of SAR by SC	April 2010
3. 30 day pre-ballot period	April – May 2010
4. Initial ballot	May 2010
5. Recirculation ballot	June 2010
6. Submit to BOT for approval	June 2010
7. File with FERC	June 2010

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-1a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective .

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-1_R1 and TPL-003-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
1a	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

<table>
<tr>
<td>D [d]

Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</td>
<td>3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure):
1. Generator
2. Transmission Circuit
3. Transformer
4. Bus Section
<hr>3Ø Fault, with Normal Clearing [e]:
5. Breaker (failure or internal Fault)
<hr>6. Loss of towerline with three or more circuits
7. All transmission lines on a common right-of way
8. Loss of a substation (one voltage level plus transformers)
9. Loss of a switching station (one voltage level plus transformers)
10. Loss of all generating units at a station
11. Loss of a large Load or major Load center
12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required
13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate
14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</td>
<td>Evaluate for risks and consequences.
▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.
▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.
▪ Evaluation of these events may require joint studies with neighboring systems.</td>
</tr>
</table>

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions should also be respected

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

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. None.

Proposed Action Plan and Description of Current Draft:

The SDT has submitted a SAR to address FERC Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System by June 30, 2010. Due to the timeframe involved, the SDT has requested an Urgent Action process be approved by the Standards Committee. To accommodate this process, the SDT has supplied drafts of the affected TPL standards as part of the SAR submittal.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit SAR to SC	April 2010
2. Approval of SAR by SC	April 2010
3. 30 day pre-ballot period	April – May 2010
4. Initial ballot	May 2010
5. Recirculation ballot	June 2010
6. Submit to BOT for approval	June 2010
7. File with FERC	June 2010

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-~~0a~~1a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective~~April 1, 2005~~.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-~~0~~1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-~~0~~1_R1 and TPL-003-~~0~~1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-~~0~~1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
~~0b~~1a	~~April 2010~~TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) ~~Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~ No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

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Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

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TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

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. None.

Proposed Action Plan and Description of Current Draft:

The SDT has submitted a SAR to address FERC Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System by June 30, 2010. Due to the timeframe involved, the SDT has requested an Urgent Action process be approved by the Standards Committee. To accommodate this process, the SDT has supplied drafts of the affected TPL standards as part of the SAR submittal.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit SAR to SC	April 2010
2. Approval of SAR by SC	April 2010
3. 30 day pre-ballot period	April – May 2010
4. Initial ballot	May 2010
5. Recirculation ballot	June 2010
6. Submit to BOT for approval	June 2010
7. File with FERC	June 2010

A. Introduction

1. **Title:** **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. **Number:** TPL-002-1b

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective .

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-1_R1 and TPL-002-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	April 2010	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	 Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	 No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	 Yes Yes Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	 No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section - - - - - - - - - - - - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - - - - - - - - - - - - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

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. None.

Proposed Action Plan and Description of Current Draft:

The SDT has submitted a SAR to address FERC Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System by June 30, 2010. Due to the timeframe involved, the SDT has requested an Urgent Action process be approved by the Standards Committee. To accommodate this process, the SDT has supplied drafts of the affected TPL standards as part of the SAR submittal.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit SAR to SC	April 2010
2. Approval of SAR by SC	April 2010
3. 30 day pre-ballot period	April – May 2010
4. Initial ballot	May 2010
5. Recirculation ballot	June 2010
6. Submit to BOT for approval	June 2010
7. File with FERC	June 2010

A. Introduction

1. **Title:** **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. **Number:** TPL-002-~~0b~~1b

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective~~Immediately after approval of applicable regulatory authorities.~~ .

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories~~,~~, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-~~0~~1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-~~0~~1_R1 and TPL-002-~~0~~1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-~~0~~1_R3.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Monitoring Responsibility**

   Compliance Monitor: Regional Reliability Organizations.
   Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

   1.2. **Compliance Monitoring Period and Reset Timeframe**

   Annually.

   1.3. **Data Retention**

   None specified.

   1.4. **Additional Compliance Information**

   None.

2. **Levels of Non-Compliance**

   2.1. **Level 1:** Not applicable.

   2.2. **Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

   2.3. **Level 3:** Not applicable.

   2.4. **Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
~~0c~~1b	April 2010	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) ~~Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~ No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

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. None.

Proposed Action Plan and Description of Current Draft:

The SDT has submitted a SAR to address FERC Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System by June 30, 2010. Due to the timeframe involved, the SDT has requested an Urgent Action process be approved by the Standards Committee. To accommodate this process, the SDT has supplied drafts of the affected TPL standards as part of the SAR submittal.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit SAR to SC	April 2010
2. Approval of SAR by SC	April 2010
3. 30 day pre-ballot period	April – May 2010
4. Initial ballot	May 2010
5. Recirculation ballot	June 2010
6. Submit to BOT for approval	June 2010
7. File with FERC	June 2010

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)

2. **Number:** TPL-001-1

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote ‘b’ in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-1_R1 and TPL-001-1_ R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

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. None.

Proposed Action Plan and Description of Current Draft:

The SDT has submitted a SAR to address FERC Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote ‘b’, regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System by June 30, 2010. Due to the timeframe involved, the SDT has requested an Urgent Action process be approved by the Standards Committee. To accommodate this process, the SDT has supplied drafts of the affected TPL standards as part of the SAR submittal.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit SAR to SC	April 2010
2. Approval of SAR by SC	April 2010
3. 30 day pre-ballot period	April – May 2010
4. Initial ballot	May 2010
5. Recirculation ballot	June 2010
6. Submit to BOT for approval	June 2010
7. File with FERC	June 2010

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)

2. **Number:** TPL-001-~~0~~1~~.1~~

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective~~May 13, 2009~~.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-~~0~~1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-~~0~~1_R1 and TPL-001-~~0~~1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-~~0~~1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1~~.~~	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) ~~Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~ No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Implementation Plan for Project 2010-11: TPL Table 1 Order

Standards Involved:

- TPL-001-1 — System Performance Under Normal (No Contingency) Conditions (Category A)
- TPL-002-1b — System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- TPL-003-1 — System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
- TPL-004-1 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

Revision to Sections of Approved Standards and Definitions

There are no new definitions in the proposed standards and no proposed changes to other standards.

Compliance with Standards

The four standards are all applicable to both the Transmission Planner and the Planning Authority.

Effective Dates

The effective date is the date entities are expected to meet the performance identified in these standards.

The application of revised Footnote ‘b’ in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective.

All other requirements remain in effect per previous approvals.

Standard Authorization Request Form

Title of Proposed Standard	2010-11 TPL Table 1 Order
Request Date	April 9, 2010
Approved by SC for Posting	April 14, 2010

SAR Requester Information	**SAR Type** (*Check a box for each one that applies.*)	
Name John Odom	☐	New Standard
Primary Contact FRCC 1408 N. Westshore Blvd., Suite 1002 Tampa, FL 33607	X	Revision to existing Standard
Telephone 1.813.207.7985 Fax 1.813.289.5646	☐	Withdrawal of existing Standard
E-mail jodom@frcc.com	☐	Urgent Action

Purpose (Describe what the standard action will achieve in support of bulk power system reliability.) Provide clarity to industry on TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system.
Industry Need (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.) The SAR is to address FERC Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system by June 30, 2010.
Brief Description (Provide a paragraph that describes the scope of this standard action.) The SAR provides a revision to TPL Table 1 footnote 'b' to provide clarity to industry with regard to the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. The referenced table appears in TPL-001, TPL-002, TPL-003, and TPL-004 so while the FERC Order was for TPL-002, the change is reflected in all 4 standards.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.) The ATFNSDT (Project 2006-02) has developed a clarification to TPL Table 1 – footnote 'b'

concerning the loss of load and handling of firm transfers when a single contingency occurs on the transmission system.

With regard to the load shedding issue, the SDT is proposing the following revision to footnote 'b':

No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

On the firm transfer issue, the SDT developed the following clarification:

No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

Since this clarification may present a different interpretation of footnote 'b' than the one presently used by some entities, the SDT is proposing a 60 month implementation plan to allow those entities time to react.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
X	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
X	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
x	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
TPL-001-0.1	System Performance Under Normal (No Contingency) Conditions (Category A)
TPL-002-0b	System Performance Following Loss of a Single Bulk Electric System Element (Category B)
TPL-003-0a	System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
TPL-004-0	System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Standards Authorization Request (SAR)
Ballot Pool and Pre-ballot Window (with Comment Period)
Project 2010-11: TPL Table 1, Footnote B

Now available at: http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

TPL Table 1, Footnote B SAR (Project 2010-11)

The Standards Committee, in response to a FERC Order issued March 18, 2010, has posted a proposed SAR, four draft standards, TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1, and an implementation plan, for a simultaneous pre-ballot review and 40-day comment period. The only change proposed in each of the four standards is to Table 1, Footnote 'b'.

The Order requires the ERO to file the revised standards by June 30. 2010. To meet this due date, the Standards Committee approved the following deviation from the standards development process:

- The proposed changes to the standards will be posted for a 40-day comment period. The Ballot Pool will be formed during the first 30 days of the 40-day comment period;
- The initial ballot will be conducted during the last 10 days of the 40-day comment period; and
- The drafting team may make modifications to the footnote between the initial and recirculation ballots based on stakeholder comments to improve the overall quality of the footnote.

Ballot Pool (through May 17, 2010)

Registered Ballot Body members may join the ballot pool to be eligible to vote on this interpretation **until 8 a.m. EDT on May 17, 2010**.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2010-11_TPL_SAR_in

Comment Period (through May 25, 2010)

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at 609-524-7047.

The status, purpose, a clean and redline version of the four standards, and supporting documents for this project — including an off-line, unofficial copy of the questions listed in the comment form — are posted at the following site: http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Project Background:

The Assess Transmission Future Needs Standard Drafting Team (Project 2006-02) has developed a clarification to TPL Table 1 — footnote 'b' concerning the loss of load and handling of firm transfers when a single contingency occurs on the transmission system.

The drafting team is proposing the following revision to footnote ‘b’: No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

On the firm transfer issue, the drafting team developed the following clarification:

No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions should also be respected.

Since this clarification may present a different interpretation of footnote ‘b’ than the one presently used by some entities, the SDT is proposing a 60 month implementation plan to allow those entities time to react.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Lauren Koller at Lauren.Koller@nerc.net

Individual or group. (22 Responses)
Name (13 Responses)
Organization (13 Responses)
Question 1 (22 Responses)
Question 1 Comments (22 Responses)
Question 2 (22 Responses)
Question 2 Comments (22 Responses)

-
Group
No
The proposed changes do not adequately address FERC's concerns in RM06-16-009. The Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." The proposed changes to footnote 'b' indicate "No interruption of firm Load is allowed except:… (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities." The exception described appears to still allow non-consequential load loss. FERC describes in RM06-16-009 non-consequential load loss as "the removal, by any means, of any firm load that is not directly served by the elements that are removed from service as a result of the contingency." In referencing Order 693, the Commission reiterated its position that TPL standards "should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency." "Must" should be used instead of "should" in the last sentence of the footnote, making it to read "Facility Ratings in those regions must also be respected."
Yes
Conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.
Individual
Robert Casey
Georgia Transmission Corporation (Bulk System Planning)
No
Georgia Transmission Corporation (GTC) believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We believe that FERC's directive in (Docket No. RM06-16) to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. We also note that on April 19 NERC filed a request for rehearing with FERC asking that the Commission revise the directive in Paragraph 8 of the March 18 TPL-002 Order to allow NERC the necessary time to incorporate changes to the TPL-002 Reliability Standard through the Reliability Standards Development Process that are necessary to achieve bulk power system reliability. NERC also requested that the Commission grant NERC's Motion for Stay to stay the Order so that a public technical conference with opportunity for comment can be held in order to provide parties an opportunity to meet and discuss the technical considerations of developing a modification to the TPL-002 standard that prohibits the loss of non-consequential firm load in the event of an N-1 contingency. NERC's April 19 filing pointed out that if the Commission's directive to disallow the loss of non-consequential firm load for an N-

1 contingency is implemented, a question is presented regarding whether the Reliability Standard still serves the purpose of ensuring the Reliable Operation of the bulk power system by preventing instability, uncontrolled separation, and cascading failures. That is, the Commission's directive sets forth an expectation that NERC is to implement standards that address all loss of load at costs that may not be commensurate with bulk power system reliability, as statutorily defined, which is fundamentally different from what the Reliability Standards were intended to do.
Yes
See response to Question #1.
Group
Yes
For better clarity delete the phrase "when coupled with" in the second paragraph of footnote 'b.'
No
The comments expressed herein represent a consensus of the views of the above named members of the SERC Engineering Committee Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.
Group
Yes
No
Individual
Thad Ness
American Electric Power
Yes
No
Individual
Kasia Mihalchuk
Manitoba Hydro
Yes
MH agrees with the SDT proposal.
No
Group
No
We propose that the section in double parentheses be deleted. The proposed wording by the drafting team seems to imply that the curtailment of firm transmission service is permitted to address single contingency constraints if coupled with the redispatch of network resources. The original language stated only that curtailments were permitted to prepare for the next contingency, not to address loading related to the initial contingency. The proposed wording could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint. Southern Companies recommend that the original language relating to "preparing for the next contingency" be incorporated into the drafting team's proposal. ((Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.)) No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch. where it can It must be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.
No
Individual

Martin Bauer
US Bureau of Reclamation
Yes
No
Group
Yes
On the firm transfer issues, the term "Firm Transmission Service" should be replaced with "Firm Transfers" to be consistent with the fourth column of the existing Table 1 Transmission System Standards - Normal and Emergency Conditions.
No
Individual
Kirit Shah
Ameren
Yes
We were ok with the previous language. Though we do not intend to drop non-consequential load for a single contingency, we undersatnd that other ares may have been following such practice without degarding the relaibility of BES. We believe that they can continue this practice if they develop non-firm contracts with these customers.
No
Group
No
For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.
No
Individual
Robert W. Roddy
Dairyland Power Cooperative
No
DPC concurs with the MRO comments: For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.
No
Individual
Marty Berland
Progress Energy
No
Progress Energy applauds NERC’s efforts to improve the footnote (b) language with respect to conditional allowance of curtailing Firm Transmission Service, which is addressed in the second paragraph of the proposed new footnote (b). PE remains concerned, however, that the first paragraph of the proposed new footnote (b) does not allow for curtailment of non-radial non-consequential load. The ability to curtail non-consequential load in the planning horizon can be a useful tool to mitigate local area issues, and has not been detrimental to the Bulk Electric System (BES). Disallowing the curtailment of non-radial non-consequential load essentially prohibits taking action in situations in which the load in question is clearly at a localized self-contained level of the system, i.e. the distribution system(s) served by the Transmission Owner/Operator. Prohibiting the curtailment of local load thus constitutes regulating distribution feeder reliability rather than BES reliability. Events that could be mitigated through the curtailment of local, non-radial non-consequential load are infrequent, and such curtailment has no material effect on the reliability of the BES. PE therefore suggests that the following addition (item (3)) to the first paragraph of the proposed footnote (b) be considered: “No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, and/or (2) Planned or controlled interruption of

Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities, and/or (3) Planned or controlled interruption of any additional Load required to mitigate the post-contingency results, provided that the non-consequential load being shed for the event is localized, and provided that the total load shed for the event does not exceed 2% of the Planned system peak demand or 200 MW, whichever value is less.”
Yes
There is the potential for conflict between Table 1 – Footnote (b) as currently proposed, which can be considered to regulate local distribution reliability without improving BES reliability, and local service reliability issues which are under the purview of state regulatory agencies. For example, the North Carolina Utilities Commission (NCUC) commented regarding this concern in the ballot which ended March 1 in Project 2006-02. Specifically, NCUC commented that they were “…concerned that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1 is an inappropriate overreach into service issues that are more appropriately addressed by state regulatory commissions…” Progress Energy believes that NCUC’s concerns are legitimate. BES reliability should address the avoidance and mitigation of cascading outages and BES facility damage, rather than limited, controlled local area loss of load, in order to avoid this conflict and overlap of regulation.
Group
Yes
Yes
This is not an issue for historic PJM members, but as PJM has expanded and as a result of the merger of historic councils into RFC, I am aware that not all regions had standards equal to those of MAAC, and this has been an issue worked out between transmission planners (historic transmission owners) and their local regulators. It is ultimately a cost issue for loss of local load that does not affect the overall reliability of the interconnected BES.
Individual
Michael R. Lombardi
Northeast Utilities
Yes
Yes
Northeast Utilities (NU) believes the language of the proposed revision to footnote ‘b’ can be better defined as the proposed revision is subject to interpretation by the different entities and regulatory agencies. Future conflicts can be minimized by further clarifying the proposed revision. Also, NU is concerned that this new modification does not specify the amount of permissible load shed nor does it require the planning entity to minimize load shedding under this exception.
Individual
Charles Lawrence
American Transmission Company
No
For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.
No
Group
Yes
Yes
It should be noted that conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC’s position on non-consequential load loss. In RM-06-16-009, the Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is “based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios.” In the US, State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position. Similar conflicts may also exist in Canada.
Individual

Greg Rowland
Duke Energy
No
Duke Energy voted "Negative" on the initial and current ballots of TPL-001-1, primarily because Duke believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We also sought rehearing on the Commission's March 18 Order Setting Deadline for Compliance (Docket No. RM06-16), with respect to this and other issues. We believe that FERC's directive in that Order to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the potential impacts (environmental, historical, archaeological, aesthetic…) of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. Duke offers the following ideas on alternatives for the SDT to consider that will allow for appropriate discretion and facilitate proper planning while allowing non-consequential load loss (NCLL). The standard should allow for dropping of limited amounts of non-consequential load in situations where it would be reasonable for a bounded time period and under restricted system conditions (e.g. 1-3 years only when load is >90 % of peak conditions). Dropping of non-consequential load would be prudent planning in situations where the near term impact of load projections or implementation of nearby transmission/generation projects will alleviate the necessity of an upgrade to meet N-1 conditions. Also, reliability of service to end-use customer is impacted by the entire system from source to load. Where allowance for NCLL would not greatly impact individual end-use customers' level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to avoid projects without greatly impacting a customer's outage frequency and duration should be acceptable. Use of reliability metrics (e.g. SAIFI/SAIDI/ASAI) should also be considered by the SDT for determination of acceptable use of NCLL.
Yes
See response to question #1.
Individual
Bill Middaugh
Tri-State Generation and Transmission Association, Inc.
No
Tri-State does believe that the new footnote is an improvement, but thinks there are still some changes necessary. We believe that the word "only" should be removed from the phrase "…where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities" because that discrimination was not required in FERC Order RM-06-16-009. There may be times when facilities near the temporary radial facilities might also fall outside the limits set in reliability criteria but the situation is mitigated if the load shedding occurs at the radial facility. The meaning of the second paragraph of the new footnote is unclear. Tri-State recommends changing it to "Curtailment of Firm Transmission Service is not allowed unless it is coupled with curtailment-offsetting resources that are obligated to re-dispatch. Further, the curtailment activities cannot result in the shedding of any Firm load or in violations of Facility Ratings, either internal or external to the planning region."
Yes
We believe that FERC's directive in FERC Order RM-06-16-009 to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load.
Group
Yes

Yes
This is an area of fuzziness between State jurisdiction and Federal jurisdiction. In all honesty, shedding load for local area impacts has nothing to do with BES reliability and should not be under FERC jurisdiction under Section 215 of the Federal Power Act, but rather State jurisdiction for quality of service issues. However, there is also the matter of FERC jurisdiction over commercial matters and the opportunity to “game” the original footnote by transmission providers by allowing firm load shedding to grant firm transmission service for themselves, thereby avoiding or deferring transmission investment, while at the same time denying or requiring others to build the same transmission avoided in order to obtain transmission service. We can see how difficult it is from a drafting team’s perspective in achieving a balanced position between these different matters. The drafting team should be applauded for finding a reasonable position.
Individual
Roger Champagne
Hydro-Québec TransÉnergie (HQT)
No
The proposed changes do not adequately address FERC’s concerns in RM06-16-009. The Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is “based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios.” The proposed changes to footnote ‘b’ indicate “No interruption of firm Load is allowed except:… (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.” The exception described appears to still allow non-consequential load loss. FERC describes in RM06-16-009 non-consequential load loss as “the removal, by any means, of any firm load that is not directly served by the elements that are removed from service as a result of the contingency.” In referencing Order 693, the Commission reiterated its position that TPL standards “should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency.” “Must” should be used instead of “should” in the last sentence of the footnote, making it to read “Facility Ratings in those regions must also be respected.”
Yes
Conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC’s position on non-consequential load loss. State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.
Individual
Dan Rochester
Independent Electricity System Operator
Yes
IESO supports the revisions made to footnote ‘b’ based on the present definitions of BES and Firm Demand and on the understanding that the NERC standards apply only to the BES as defined in the NERC Glossary as follows: “As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.” To be clear, our interpretation of the present definition of BES is that it defers to each Regional Reliability Organization to define the elements of the power system that are considered BES and, therefore in the NPCC Region, "BES as defined by NERC" = "BPS as defined by NPCC".
No

Consideration of Comments on Project 2010-11: TPL Table 1 Order and Comments Submitted with Initial Ballots

The Standards Committee thanks all commenters who submitted comments on the proposed SAR for the TPL Table 1 Order. The SAR proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which requires the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards.

The SAR, implementation plan, and the clean and redline versions to the four TPL standards were posted for a 40-day public comment period from April 15, 2010 through May 27, 2010. Stakeholders were asked to provide feedback on the standards through a special electronic comment form. There were 22 sets of comments, including comments from more than 80 different people from approximately 40 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

The initial ballot for the proposed changes to the four TPL standards was conducted from May 17-27, 2010. The comments submitted with initial ballots and the drafting team's responses to those comments are also contained in this report.

All comments submitted during the comment period and the initial ballot results are posted on the following page:

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Based on stakeholder comments, the drafting team has made some additional changes to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

The following bullet was added to Footnote 'b' to provide the flexibility requested by stakeholders with respect to interrupting Demand, but with appropriate constraints to protect reliability. The >90% demand level was selected to ensure that the number of hours with exposure to demand loss was not unlimited. A 90% demand level is a reasonably stressed case for most systems and the number of hours when peak demands are >90% is a small percentage of the time for most systems. A large percentage of the transmission lines that directly serve distribution customers are 161 kV or lower voltages. Ten percent (10%) of the loading on a high capacity 161 kV transmission line is approximately 50 MW.

- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW

The following bullet was added to Footnote ‘b’ to clarify that it is acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

The above changes will be noted to stakeholders before the initiation of the recirculation ballot.

The revised Footnote ‘b’ is:

b) No interruption of projected customer Demand is allowed except:

- Interruption of Demand that is directly served by the elements that are removed from service as a result of the Contingency
- Planned or controlled interruption of Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

If you feel that your comment has been overlooked, 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, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Comments and Responses from Formal Comment Period:

Comments and Responses from Initial Ballot:

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, 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, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
4.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
5.	Sylvain Clermont	Hydro-Quebec TransEnergie		1
6.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
7.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
8.	Ben Eng	New York Power Authority	NPCC	4
9.	Brian Evans-Mongeon	Utility Services	NPCC	8
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
11.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
12.	Kathleen Goodman	ISO - New England	NPCC	2
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1
14.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
15. Randy MacDonald			New Brunswick System Operator	NPCC					2				
16. Bruce Metruck			New York Power Authority	NPCC					6				
17. Lee Pedowicz			Northeast Power Coordinating Council	NPCC					10				
18. Robert Pellegrini			The United Illuminating Company	NPCC					1				
19. Saurabh Saksena			National Grid	NPCC					1				
20. Michael Schiavone			National Grid	NPCC					1				
2.	Group	Philip R. Kleckley	South Carolina Electric & Gas	X		X		X					
Additional Member			Additional Organization	Region					Segment Selection				
1. Bob Jones			Southern Company Services - Trans.	SERC					1				
2. David Marler			Tennessee Valley Authority	SERC					1				
3. Charles Long			Entergy	SERC					1				
4. James Manning			North Carolina Electric Membership Corporation	SERC					3				
5. Pat Huntley			SERC Reliability Corporation	SERC					10				
3.	Group	John Bee	Exelon Transmission Strategy & Compliance	X		X		X					
Additional Member			Additional Organization	Region					Segment Selection				
1. Mortenson, Eric			:(ComEd)	RFC					1				
2. Weaver, David W			(PECO)	RFC					1				
3. McHugh, Kathleen P			(PECO)	RFC					1				
4. Kay, Thomas W			(ComEd)	RFC					1				
5. Szymczak, Ronald			(ComEd)	RFC					1				
6. Chu, Ron F			(PECO)	RFC					1				
7. Donnelly, Michael J			(PECO)	RFC					1				
8. Kliros, Chris B			(ComEd)	RFC					1				
9. Mills, Paul M			(ComEd)	RFC					1				
10. Webb, Becky			(ComEd)	RFC					1				
4.	Group	Denise Koehn	BPA, Transmission Reliability Program	X		X		X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
	Additional Member		**Additional Organization**	**Region**					**Segment Selection**				
1.	Chuck Matthews		BPA, Transmission Planning	WECC					1				
2.	Berhanu Tesema		BPA, Transmission Planning	WECC					1				
3.	Larry Furumasu		BPA, Transmission Planning	WECC					1				
4.	Kyle Kohne		BPA, Transmission Planning	WECC					1				
5.	Don Watkins		BPA, Transmission System Operations	WECC					1				
6.	Rebecca Berdahl		BPA, Power, Long Term Sales and Purchases	WECC					3				
5.	Group	Carol Gerou	Midwest Reliability Organization										X
	Additional Member		**Additional Organization**	**Region**					**Segment Selection**				
1.	Chuck Lawrence		American Transmission Company	MRO					1				
2.	Tom Webb		Wisconsin Public Service	MRO					3, 4, 5, 6				
3.	Terry Bilke		Midwest ISO Inc.	MRO					2				
4.	Jodi Jenson		Western Area Power Administration	MRO					1, 6				
5.	Ken Goldsmith		Alliant Energy	MRO					4				
6.	Dave Rudolph		Basin Electric Power Cooperative	MRO					1, 3, 5, 6				
7.	Eric Ruskamp		Lincoln Electric System	MRO					1, 3, 5, 6				
8.	Joseph Knight		Great River Energy	MRO					1, 3, 5, 6				
9.	Joe DePoorter		Madison Gas & Electric	MRO					3, 4, 5, 6				
10.	Scott Nickels		Rochester Public Utilities	MRO					4				
11.	Terry Harbour		MidAmerican Energy Company	MRO					1, 3, 5, 6				
6.	Group	Richard Kafka	Pepco Holdings, Inc.	X		X		X	X				
	Additional Member		**Additional Organization**	**Region**					**Segment Selection**				
1.	Jim Summers		Delmarva Power and Light Co.	RFC					1				
2.	John Radman		Potomac Electric Power Company	RFC					1				
7.	Group	Ben Li	IESO		X								
	Additional Member		**Additional Organization**	**Region**					**Segment Selection**				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Bill Phillips		MISO	MRO									
2.	James Castle		NYISO	NPCC									
3.	Charles Yeung		SPP	SPP									
4.	Lourdes Estrada-Salinero		CAISO	WECC									
5.	Patrick Brown		PJM	RFC									
6.	Steve Myers		ERCOT	ERCOT									
8.	Group	Frank Gaffney	Florida Municipal Power Agency	X			X	X	X				
	Additional Member		**Additional Organization**	**Region**					**Segment Selection**				
1.	Timothy Beyrle		Utilities Commission of New Smyrna Beach	FRCC					4				
2.	Greg Woessner		Kissimmee Utility Authority	FRCC					1				
3.	Jim Howard		Lakeland Electric	FRCC					1				
4.	Lynne Mila		City of Clewiston	FRCC					3				
5.	Joe Stonecipher		Beaches Energy Services	FRCC					1				
6.	Cairo Vanegas		Fort Pierce Utility Authority	FRCC					4				
9.	Individual	Stephen Mizelle	Southern Company Transmission	X									
10.	Individual	Robert Casey	Georgia Transmission Corporation (Bulk System Planning)	X									
11.	Individual	Thad Ness	American Electric Power	X		X		X	X				
12.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
13.	Individual	Martin Bauer	US Bureau of Reclamation					X					
14.	Individual	Kirit Shah	Ameren	X		X		X	X				
15.	Individual	Robert W. Roddy	Dairyland Power Cooperative	X		X		X					

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
16.	Individual	Marty Berland	Progress Energy	X		X		X	X				
17.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X					
18.	Individual	Charles Lawrence	American Transmission Company	X									
19.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
20.	Individual	Bill Middaugh	Tri-State Generation and Transmission Association, Inc.	X		X		X	X				
21.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									
22.	Individual	Dan Rochester	Independent Electricity System Operator		X								

1. The SDT is proposing a revision to footnote 'b' in the TPL tables to comply with FERC Order RM-06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system by June 30, 2010. Do you agree with the proposed changes and if not, please provide specific reasons for your disagreement.

Summary Consideration: The SDT has listened to the comments from the industry, understands the concerns raised, and has made changes to the footnote to balance the various industry concerns while assuring BES reliability.

The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. This is limited by two conditions: >90% demand level and 50 MW. The >90% demand level was selected to ensure that the number of hours with exposure to demand loss was not unlimited. A 90% demand level is a reasonably stressed case for most systems and the number of hours when peak demands are >90% is a small percentage of the time for most systems. A large percentage of the transmission lines that directly serve distribution customers are 161 kV or lower voltages. Ten percent (10%) of the demand on a high capacity 161 kV transmission line is approximately 50 MW.

A 4th bullet has also been added to clarify that it is acceptable to use Interruptible demand and Demand-Side Management.

To match the terminology in the revised footnote with the terminology in the associated column heading (Loss of Demand or Curtailed Firm Transfers) the term, 'Load' was replaced with 'Demand' and the term 'Firm Transmission Service' was replaced with 'firm transfers.'

Footnote 'b' now reads:

b)~~-~~No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Duke Energy	No	Duke Energy voted "Negative" on the initial and current ballots of TPL-001-1, primarily because Duke believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We also sought rehearing on the Commission's March 18 Order Setting Deadline for Compliance (Docket No. RM06-16), with respect to this and other issues. We believe that FERC's directive in that Order to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the potential impacts (environmental, historical, archaeological, aesthetic...) of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. Duke offers the following ideas on alternatives for the SDT to consider that will allow for appropriate discretion and facilitate proper planning while allowing non-consequential load loss (NCLL).The standard should allow for dropping of limited amounts of non-consequential load in situations where it would be reasonable for a bounded time period and under restricted system conditions (e.g. 1-3 years only when load is >90 % of peak conditions). Dropping of non-consequential load would be prudent planning in situations where the near term impact of load projections or implementation of nearby transmission/generation projects will alleviate the necessity of an upgrade to meet N-1 conditions. Also, reliability of service to end-use customer is impacted by the entire system from source to load. Where allowance for NCLL would not greatly impact individual end-use customers' level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to avoid projects without greatly impacting a customer's outage frequency

Organization	Yes or No	Question 1 Comment
		and duration should be acceptable. Use of reliability metrics (e.g. SAIFI/SAIDI/ASAI) should also be considered by the SDT for determination of acceptable use of NCLL.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. The SDT discussed the use of reliability metrics for providing flexibility to planners but has not included their use as this would make the implementation too complex.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Midwest Reliability Organization	No	For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.
Dairyland Power Cooperative	No	DPC concurs with the MRO comments: For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.
American Transmission Company	No	For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant

Organization	Yes or No	Question 1 Comment
		transmission system modifications.

Response: The SDT has added the fourth bullet to address your concern.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- o Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Georgia Transmission Corporation (Bulk System Planning)	No	Georgia Transmission Corporation (GTC) believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We believe that FERC's directive in (Docket No. RM06-16) to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view

Organization	Yes or No	Question 1 Comment
		to allow loss of non-consequential load.We also note that on April 19 NERC filed a request for rehearing with FERC asking that the Commission revise the directive in Paragraph 8 of the March 18 TPL-002 Order to allow NERC the necessary time to incorporate changes to the TPL-002 Reliability Standard through the Reliability Standards Development Process that are necessary to achieve bulk power system reliability. NERC also requested that the Commission grant NERC's Motion for Stay to stay the Order so that a public technical conference with opportunity for comment can be held in order to provide parties an opportunity to meet and discuss the technical considerations of developing a modification to the TPL-002 standard that prohibits the loss of non-consequential firm load in the event of an N-1 contingency. NERC's April 19 filing pointed out that if the Commission's directive to disallow the loss of non-consequential firm load for an N-1 contingency is implemented, a question is presented regarding whether the Reliability Standard still serves the purpose of ensuring the Reliable Operation of the bulk power system by preventing instability, uncontrolled separation, and cascading failures. That is, the Commission's directive sets forth an expectation that NERC is to implement standards that address all loss of load at costs that may not be commensurate with bulk power system reliability, as statutorily defined, which is fundamentally different from what the Reliability Standards were intended to do.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- o Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Progress Energy	No	Progress Energy applauds NERC's efforts to improve the footnote (b) language with respect to conditional allowance of curtailing Firm Transmission Service, which is addressed in the second paragraph of the proposed new footnote (b). PE remains concerned, however, that the first paragraph of the proposed new

Organization	Yes or No	Question 1 Comment
		footnote (b) does not allow for curtailment of non-radial non-consequential load. The ability to curtail non-consequential load in the planning horizon can be a useful tool to mitigate local area issues, and has not been detrimental to the Bulk Electric System (BES). Disallowing the curtailment of non-radial non-consequential load essentially prohibits taking action in situations in which the load in question is clearly at a localized self-contained level of the system, i.e. the distribution system(s) served by the Transmission Owner/Operator. Prohibiting the curtailment of local load thus constitutes regulating distribution feeder reliability rather than BES reliability. Events that could be mitigated through the curtailment of local, non-radial non-consequential load are infrequent, and such curtailment has no material effect on the reliability of the BES. PE therefore suggests that the following addition (item (3)) to the first paragraph of the proposed footnote (b) be considered:"No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, and/or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities, and/or (3) Planned or controlled interruption of any additional Load required to mitigate the post-contingency results, provided that the non-consequential load being shed for the event is localized, and provided that the total load shed for the event does not exceed 2% of the Planned system peak demand or 200 MW, whichever value is less."

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. The SDT did adopt a limit but felt that 2% of system peak or 200 MW was not equitable for all entities.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Hydro-Québec TransEnergie (HQT)	No	The proposed changes do not adequately address FERC's concerns in RM06-16-009. The Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." The proposed changes to footnote 'b' indicate "No interruption of firm Load is allowed except:... (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities." The exception described appears to still allow non-consequential load loss. FERC describes in RM06-16-009 non-consequential load loss as "the removal, by any means, of any firm load that is not directly served by the elements that are removed from service as a result of the contingency." In referencing Order 693, the Commission reiterated its position that TPL standards "should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency." "Must" should be used instead of "should" in the last sentence of the footnote, making it to read "Facility Ratings in those regions must also be respected."
Northeast Power Coordinating Council	No	The proposed changes do not adequately address FERC's concerns in RM06-16-009. The Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." The proposed changes to footnote 'b' indicate "No interruption of firm Load is allowed except:... (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities." The exception described appears to still allow non-consequential load loss. FERC describes in RM06-16-009 non-consequential load loss as "the removal, by any means, of any firm load that is not directly served by the elements that are removed from service as a result of the contingency." In referencing Order 693, the Commission reiterated its position that TPL standards "should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency." "Must" should be used instead of "should" in the last sentence of the footnote, making it to read "Facility Ratings in those regions must also be respected."

Response: The SDT believes that it has been responsive to the FERC directive in that the standards development process has been employed. In the

Organization	Yes or No	Question 1 Comment
development of the footnote, the SDT has balanced the need for discretion while addressing local area concerns with the need to assure the reliability of the BES. 'Must' is not appropriate in a footnote as it would impose a requirement in the footnote. The SDT has replaced 'should' with 'would' to correct the grammar. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Tri-State Generation and Transmission Association, Inc.	No	Tri-State does believe that the new footnote is an improvement, but thinks there are still some changes necessary. We believe that the word "only" should be removed from the phrase "...where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities" because that discrimination was not required in FERC Order RM-06-16-009. There may be times when facilities near the temporary radial facilities might also fall outside the limits set in reliability criteria but the situation is mitigated if the load shedding occurs at the radial facility. The meaning of the second paragraph of the new footnote is unclear. Tri-State recommends changing it to "Curtailment of Firm Transmission Service is not allowed unless it is coupled with curtailment-offsetting resources that are obligated to re-dispatch. Further, the curtailment activities cannot result in the shedding of any Firm load or in violations of Facility Ratings, either internal or external to the planning region."
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. Instead of removing the word 'only', the 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:		

Organization	Yes or No	Question 1 Comment
		o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Southern Company Transmission	No	We propose that the section in double parentheses be deleted. The proposed wording by the drafting team seems to imply that the curtailment of firm transmission service is permitted to address single contingency constraints if coupled with the redispatch of network resources. The original language stated only that curtailments were permitted to prepare for the next contingency, not to address loading related to the initial contingency. The proposed wording could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint. Southern Companies recommend that the original language relating to "preparing for the next contingency" be incorporated into the drafting team's proposal.((Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.)) No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch. where it can It must be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

Organization	Yes or No	Question 1 Comment
Response: The SDT believes that System re-dispatch is an acceptable System adjustment to "remain within applicable Facility Ratings" to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can be only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the Firm Transmission Service cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the paragraph. The SDT made editorial changes to the 2[nd] paragraph to provide additional clarity in response to your comment and those of others. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
South Carolina Electric & Gas	Yes	For better clarity delete the phrase "when coupled with" in the second paragraph of footnote 'b.'
Response: The SDT did not delete the suggested phrase as it believes it is correct as stated but added commas to make the phrase read more clearly. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~		

Organization	Yes or No	Question 1 Comment
o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Independent Electricity System Operator	Yes	IESO supports the revisions made to footnote 'b' based on the present definitions of BES and Firm Demand and on the understanding that the NERC standards apply only to the BES as defined in the NERC Glossary as follows:"As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition." To be clear, our interpretation of the present definition of BES is that it defers to each Regional Reliability Organization to define the elements of the power system that are considered BES and, therefore in the NPCC Region, "BES as defined by NERC" = "BPS as defined by NPCC".
Response: The SDT agrees that the standard applies to the BES as defined in the Glossary.		
BPA, Transmission Reliability Program	Yes	On the firm transfer issues, the term "Firm Transmission Service" should be replaced with "Firm Transfers" to be consistent with the fourth column of the existing Table 1 Transmission System Standards - Normal and Emergency Conditions.
Response: The SDT agrees and has made the change. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW		

Organization	Yes or No	Question 1 Comment
o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
American Electric Power	Yes	
Exelon Transmission Strategy & Compliance	Yes	
Florida Municipal Power Agency	Yes	
IESO	Yes	
Northeast Utilities	Yes	
Pepco Holdings, Inc.	Yes	
US Bureau of Reclamation	Yes	
Manitoba Hydro	Yes	MH agrees with the SDT proposal.
Ameren	Yes	We were ok with the previous language. Though we do not intend to drop non-consequential load for a single contingency, we undersatnd that other ares may have been following such practice without degarding the relaibility of BES. We believe that they can continue this practice if they develop non-firm contracts with these customers.
Response: Thank you for your support.		

2. Are you aware of any conflicts caused by compliance with the proposed language in Table 1 — footnote b and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement? If yes, please identify the conflict.

Summary Consideration: The SDT understands that there may be conflicts as pointed out by respondents; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.

b) ~~–~~No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
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~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 2 Comment
Ameren	No	
American Electric Power	No	
American Transmission Company	No	
BPA, Transmission Reliability	No	

Organization	Yes or No	Question 2 Comment
Program		
Dairyland Power Cooperative	No	
Exelon Transmission Strategy & Compliance	No	
Independent Electricity System Operator	No	
Manitoba Hydro	No	
Midwest Reliability Organization	No	
Southern Company Transmission	No	
US Bureau of Reclamation	No	
South Carolina Electric & Gas	No	The comments expressed herein represent a consensus of the views of the above named members of the SERC Engineering Committee Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.
Response: Thank you for your response.		
Hydro-Québec TransEnergie (HQT)	Yes	Conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.
Northeast Power Coordinating Council	Yes	Conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.

Organization	Yes or No	Question 2 Comment
IESO	Yes	It should be noted that conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. In RM-06-16-009, the Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." In the US, State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.Similar conflicts may also exist in Canada.
Progress Energy	Yes	There is the potential for conflict between Table 1 - Footnote (b) as currently proposed, which can be considered to regulate local distribution reliability without improving BES reliability, and local service reliability issues which are under the purview of state regulatory agencies. For example, the North Carolina Utilities Commission (NCUC) commented regarding this concern in the ballot which ended March 1 in Project 2006-02. Specifically, NCUC commented that they were "...concerned that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1 is an inappropriate overreach into service issues that are more appropriately addressed by state regulatory commissions..." Progress Energy believes that NCUC's concerns are legitimate. BES reliability should address the avoidance and mitigation of cascading outages and BES facility damage, rather than limited, controlled local area loss of load, in order to avoid this conflict and overlap of regulation.
Response: The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.		
Northeast Utilities	Yes	Northeast Utilities (NU) believes the language of the proposed revision to footnote 'b' can be better defined as the proposed revision is subject to interpretation by the different entities and regulatory agencies. Future conflicts can be minimized by further clarifying the proposed revision. Also, NU is concerned that this new modification does not specify the amount of permissible load shed nor does it require the planning entity to minimize load shedding under this exception.
Response: The SDT has made several clarifying changes to the footnote which should alleviate your concerns. The SDT has modified the footnote for clarity and added constraints in new bullet 3 to address your specific concern.		

Organization	Yes or No	Question 2 Comment
b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Duke Energy	Yes	See response to question #1.
Georgia Transmission Corporation (Bulk System Planning)	Yes	See response to Question #1.
Response: See response to question #1.		
Florida Municipal Power Agency	Yes	This is an area of fuzziness between State jurisdiction and Federal jurisdiction. In all honesty, shedding load for local area impacts has nothing to do with BES reliability and should not be under FERC jurisdiction under Section 215 of the Federal Power Act, but rather State jurisdiction for quality of service issues. However, there is also the matter of FERC jurisdiction over commercial matters and the opportunity to "game" the original footnote by transmission providers by allowing firm load shedding to grant firm transmission service for themselves, thereby avoiding or deferring transmission investment, while at the same time denying or requiring others to build the same transmission avoided in order to obtain transmission service. We can see how difficult it is from a drafting team's perspective in achieving a balanced position between these different matters. The drafting team should be applauded for finding a reasonable position.
Pepco Holdings, Inc.	Yes	This is not an issue for historic PJM members, but as PJM has expanded and as a result of the merger of historic councils into RFC, I am aware that not all regions had standards equal to those of MAAC, and this

Organization	Yes or No	Question 2 Comment
		has been an issue worked out between transmission planners (historic transmission owners) and their local regulators. It is ultimately a cost issue for loss of local load that does not affect the overall reliability of the interconnected BES.
Response: Thank you for your support.		
Tri-State Generation and Transmission Association, Inc.	Yes	We believe that FERC's directive in FERC Order RM-06-16-009 to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load.
Response: The SDT is not in a position to comment on FERC's authority. The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.		

3. Consideration of Comments on Initial Ballot — TPL Table 1 Order (Project 2010-11) May 17–27, 2010

Summary Consideration: The SDT has listened to the comments from the industry, understands the concerns raised, and has made changes to the footnote to balance the various industry concerns while assuring BES reliability.

The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. This is limited by two conditions: >90% demand level and 50 MW. The >90% demand level was selected to ensure that the number of hours with exposure to demand loss was not unlimited. A 90% demand level is a reasonably stressed case for most systems and the number of hours when peak demands are >90% is a small percentage of the time for most systems. A large percentage of the transmission lines that directly serve distribution customers are 161 kV or lower voltages. Ten percent (10%) of the demand on a high capacity 161 kV transmission line is approximately 50 MW.

A 4th bullet has also been added to clarify that it is acceptable to use Interruptible demand and Demand-Side Management.

The second paragraph of the footnote has been clarified and references Firm Transfers now instead of Firm Transmission Service.

b)~~-~~No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Rodney Phillips	Allegheny Power	1	Negative	Allegheny Power believes the loss of non-consequential load and/or curtailment of transmission service for N-1 contingencies should be limited to only extreme circumstances. Exception 2 of footnote b allows for the loss of non-consequential load for N-1

Voter	Entity	Segment	Vote	Comment
				contingencies with no restriction. Allegheny Power recommends removing exception 2 footnote b.
Response: The SDT and the majority of the commenters disagree with this suggestion.				
Gordon Rawlings	BC Transmission Corporation	1	Negative	BCTC appreciates the good work of the SAR committee in drafting the changes to Footnote b of Table 1. BCTC agrees with the drafting team that interruption of firm load, served by either radial circuits or circuits that have became radial as a result of the contingency, should be allowed for N-1 contingencies. However, it is our position that interruption of firm load should not be limited only to such consequential loads. In our view, interruption of electric supply to some local network customers in the affected area should be permissible. This inclusion will allow transmission planners to plan BCTC's regional transmission network reliably and without impacting neighbouring transmission networks.
Faramarz Amjadi	BC Transmission Corporation	2	Negative	
Hubert C. Young	South Carolina Electric & Gas Co.	3	Negative	SCE&G has significant concern with the proposed revision to TPL Table 1, Footnote B. The current Footnote B states "Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems". The phrase "without impacting the overall reliability of the interconnected transmission systems" is important to the TPL standards to ensure that ERO standards do not dictate the level of service to customers. Service to customers and load pockets is jurisdictional to State Commissions and ERO standards should not compromise this jurisdiction. SCE&G believes that any proposed revisions to Footnote B must retain the concept that planned or controlled interruption of electric supply to customers, whether they are radial or network, is allowed as long as it does not impact the overall reliability of the interconnected transmission systems. The proposed revision eliminates this concept. There seems to be a general inconsistency and maybe confusion between the terms "reliability" and "level of service".
David Frank Ronk	Consumers Energy	4	Negative	The current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the previous version of TPL-001-1. However, it still does not allow Transmission Planners to use appropriate and necessary discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should control the decision making when BES reliability is not an issue. Often, the consequences of these events are solely local in nature, requiring only minor additional loss of local load to
James B Lewis	Consumers Energy	5	Negative	

Voter	Entity	Segment	Vote	Comment
				avoid the costly major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load.
Hugh A. Owen	Public Utility District No. 1 of Chelan County	6	Negative	The interruption of a small amount of load is, under most conditions, not a risk to the reliability of the BES and is at times necessary to preserve reliability. The planned interruption of some load may be a cost effective alternative to a costly transmission project. That is a quality of service issue.
Michael Gammon	Kansas City Power & Light Co.	1	Negative	While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load.
Charles Locke	Kansas City Power & Light Co.	3	Negative	
Thomas Saitta	Kansas City Power & Light Co.	6	Negative	
Linda Brown	San Diego Gas & Electric	1	Affirmative	As to item (1), all load served directly by a transmission element which experiences a fault will be interrupted when the faulted element is taken out of service. This is the natural relationship between the load and the transmission element. Allowing this for BES elements may encourage transmission owners to remove transmission instead of upgrading or replacing it. Consider a load supplied by two transmission lines of different capacity. If the larger line is lost due to a contingency (N-1) and the remaining smaller line overloads the transmission owner is left with several options to address the problem: (1) move load between buses, (2) upgrade the smaller line, (3) add another line, or (4) create a radial load by removing the smaller line. Number (4) may be the least expensive and allowable under TPL-002, footnote b. Item (2) may also encourage transmission owners to develop plans which make load shedding part of category B. Consider a load served by three transmission lines, a utility may decide to remove a line, instead of upgrading, in order to set up a situation where an N-1 contingency would make the bus temporarily radial. In the event of a single outage (N-1), the load bus will be temporarily radial and load can be shed at the bus.

Voter	Entity	Segment	Vote	Comment
W. R. Schoneck	Florida Power & Light Co.	3	Affirmative	I believe the language is an improvement and clarifies the intent but I believe there still should be additional language added to give an exemption in meeting this requirement if it does not make economic sense(not economically feasible) and has no real impact on the BES.
Richard J Kafka	Potomac Electric Power Co.	1	Affirmative	It is understood that this is a compliance filing issue. This is not an issue for historic PJM members, but as PJM has expanded and as a result of the merger of historic councils into RFC, I am aware that not all regions had standards equal to those of MAAC, and this has been an issue worked out between transmission planners (historic transmission owners) and their local regulators. It is ultimately a cost issue for loss of local load that does not affect the overall reliability of the interconnected BES.
Alan Gale	City of Tallahassee	5	Affirmative	TAL thanks for SDT for the tireless effort to get to this point. TAL is voting affirmative with the following comments. We accept that the loss of non-consequential load is not a desired result for N-1 contingencies. It is also not the norm in system planning or operations. The flexibility to operate the system consistent with “good utility practice” may warrant the “odd-ball” case that would require this to occur. The dropping of non-consequential load will NOT lead to BES instability, voltage collapse, or cascading outages, which is what FERC and NERC are charged with preventing. It will lead to the shedding of load in a local area only. Utilities do not drop customers lightly. If the meter isn’t turning, we are not getting paid, so we want the meter spinning. Utility power, while vital to our normal day-to-day lives and infrastructure, was never intended to be without interruption.
Brad Chase	Orlando Utilities Commission	1	Affirmative	This change raises the bar on transmission system performance. This change applies a blanket requirement upon entities that does not take into account the number of outages, probability of outages or cost to the customer. There are certain to be situations where this blanket requirement will result in increased cost to customers for no noticeable increase in reliability. OUC does agree with the concept of greater clarification on this requirement, however this clarification may raise the bar to far by trying to establish a blanket requirement. Duke, Progress Energy and others will be submitting comments with proposed language that attempt to address some of these issues and we encourage the drafting team to consider those comments.
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate				

Voter	Entity	Segment	Vote	Comment
				constraints. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Eric Egge	Black Hills Corp	1	Negative	Black Hills believes that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.

Voter	Entity	Segment	Vote	Comment
Chifong L. Thomas	Pacific Gas and Electric Company	1	Negative	PG&E commends the SDT for developing the proposed footnote b. While it is a great improvement over the complete prohibition on loss of non-consequential load for any single contingency, the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system, especially where the impact is local in nature, to avoid instability, cascading or uncontrolled separation. Such planned interruption of load may be a reasonable alternative to the environmental impacts or prohibitive costs associated with a major new transmission project. Given the potential impacts of the proposed modification, further vetting of the issues is needed. PG&E believes that NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
Thomas J. Bradish	RRI Energy	5	Negative	RRI supports the WECC position on this issue; namely, that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
Trent Carlson	RRI Energy	6	Negative	

Voter	Entity	Segment	Vote	Comment
John Tolo	Tucson Electric Power Co.	1	Negative	The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project.
James Tucker	Deseret Power	1	Negative	The prohibition of loss of non-consequential load for events resulting the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
Louise McCarren	Western Electricity Coordinating Council	10	Negative	The proposed revisions to footnote b of Table 1 are an improvement to the recently balloted prohibition on loss of non-consequential load for single contingencies. The recognition of the new term "temporarily radial" is a step in the right direction. However, the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their

Voter	Entity	Segment	Vote	Comment
				individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
William Mitchell Chamberlain	California Energy Commission	9	Negative	While the proposed revisions to footnote b are an improvement to the prohibition on loss of non-consequential load for a single contingency proposed in the recently failed TPL-001-1 ballot, the prohibition of loss of non-consequential load for events resulting the loss of a single element still inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
John Mick	Colorado Springs Utilities	6	Negative	Colorado Springs Utilities ballot on the proposed changes to TPL Table 1, footnote b directed in FERC Order RM06-16-009 Colorado Springs Utilities wishes to vote NO on the proposed changes to TPL Table 1, footnote b, directed in FERC Order RM06-16-009. CSU concurs with the WECC position paper for the ballot, and agrees with the WECC statement "that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues".
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.				

Voter	Entity	Segment	Vote	Comment

The SDT agrees that a technical conference on this issue would be of value.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- o Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Horace Stephen Williamson	Southern Company Services, Inc.	1	Negative	Comments have already been submitted previously, but it will be added here again. Proposed footnote should read... No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers when coupled with the appropriate re-dispatch of resources obligated to re-dispatch. It must be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. The proposed changes are based on the
Richard J. Mandes	Alabama Power Company	3	Negative	
Anthony L Wilson	Georgia Power Company	3	Negative	

Voter	Entity	Segment	Vote	Comment
Gwen S Frazier	Gulf Power Company	3	Negative	following... "The proposed wording by the drafting team seems to imply that the curtailment of firm transmission service is permitted to address single contingency constraints if coupled with the redispatch of network resources. The original language stated only that curtailments were permitted to prepare for the next contingency, not to address loading related to the initial contingency. The proposed wording could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint. Southern Companies recommend that the original language relating to "preparing for the next contingency" be incorporated into the drafting team's proposal."
Don Horsley	Mississippi Power	3	Negative	
Michael Ibold	Xcel Energy, Inc.	3	Negative	The proposed modification to footnote b of Table I in TPL-001 - 004 standards states that after a Category B contingency, there should not be any thermal, voltage or stability violation, no interruption of firm load (except the load that is directly connected to the elements that are removed from service as a result of the contingency) and no firm transfer curtailment (except when coupled with re-dispatch of resources obligated to re-dispatch). We believe the proposed footnote b creates a gap between TPL-002 and TPL-003 standards, since it does not address conditions when firm load shedding and firm transfer curtailments are not required to meet the system performance for Category B contingency, but one or both are the required system adjustments to prepare for the next contingency (Category C3). When firm transfer is curtailed after the first contingency in preparation for the next contingency, it is not clear from the proposed footnote b if this is considered a valid system adjustment for Category C or a violation of Category B. Recall that the existing footnote b addresses this condition explicitly by stating "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm Transfers."
Liam Noailles	Xcel Energy, Inc.	5	Negative	
David F. Lemmons	Xcel Energy, Inc.	6	Negative	
George T. Ballew	Tennessee Valley Authority	5	Affirmative	TVA appreciates the work of the SDT on this issue. However, TVA recommends revising the second paragraph of the revised footnote b: "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. However, curtailment of Firm Transmission Service is only allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility
Marjorie S. Parsons	Tennessee Valley Authority	6	Affirmative	

Voter	Entity	Segment	Vote	Comment
				Ratings in those regions should also be respected." Without the changes in the first two sentences above, the proposed wording by the SDT could be interpreted to allow re-dispatch/firm curtailments to address any single contingency constraint instead of in preparation for the next contingency.
Larry Akens	Tennessee Valley Authority	1	Affirmative	TVA appreciates the work of the SDT. However, TVA recommends revising the second paragraph of the revised footnote "b". Without changes in the first two sentences, the proposed wording by the SDT could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint instead of in preparation for the next contingency.

Response: The SDT believes that System re-dispatch is an acceptable System adjustment to "remain within applicable Facility Ratings" to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can be only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the Firm Transmission Service cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Robert W. Roddy	Dairyland Power Coop.	1	Negative	DPC CONCURS WITH THE MRO COMMENTS.
Jason Shaver	American Transmission Company, LLC	1	Affirmative	For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed if the tripping of the load is either accepted or volunteered by the customer.
Lawrence R. Larson	Otter Tail Power Company	1	Negative	The change precludes the use of direct load control systems that should be allowed to relieve transmission problems. These systems control firm transmission load but rate conditions can allow their use to mitigate transmission problems.

Response: *(Note - MRO did not submit comments with the initial ballot – but did submit the following comment during the formal comment period: For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.)*

The SDT has added the fourth bullet to address your concern.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Ajay Garg	Hydro One Networks, Inc.	1	Negative	Hydro One is casting a negative vote for the following reasons: 1. The amendment to the footnote does not add any technical value to the standard. It was added only to satisfy a FERC directive to address comments made to allow non-consequential load loss after a single contingency event, “based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios.” 2. Addressing curtailment of Firm Transmission Service with re-dispatch of resources is a matter of a commercial nature and should be dealt with in the agreements dealing with such services. Issues of contracted transmission services, firm or otherwise, are not a reliability related matter and are not to be dealt with in this standard. 3. Matters of interruption of firm load should be incorporated into this standard only after the FERC NOPR on the definition of the BES is resolved. As it stands, the footnote will pose significant problems if the 100 kV and above FERC proposal is applied across the board, unless the standard specifically states that it applies to the BES as defined by the region (current definition).
Michael D. Penstone	Hydro One Networks, Inc.	3	Negative	
Response: 1. & 2. The SDT disagrees – there is a direct impact on reliability of the BES associated with these concerns. The SDT has added clarity to the footnote by designating constraints for Demand and firm transfer curtailment. 3. The SDT disagrees that this needs to wait on the FERC NOPR. This standard is applicable to the BES as it is defined.				
Spencer Tacke	Modesto Irrigation District	4	Negative	I am voting NO vote because of the lack of clarity of the second paragraph of the proposed change. Although paragraph 1 is an improvement to the current wording, and actually allows for some specific flexibility in shedding load for an N-1 event, the lack of clarity in the second paragraph could lead to varied interpretations by members and compliance auditors. Thank you.
Response: The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:				

Voter	Entity	Segment	Vote	Comment
				o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Dana Cabbell	Southern California Edison Co.	1	Negative	It is SCE's position that the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. When planned load interruption is identified as a response to a single event, the impact to the system is often local in nature. The planned interruption of load may be a desirable alternative to the prohibitive costs associated with a major new transmission project. If the NERC Standards Drafting Team decides to proceed with footnote B, as written, it needs to ensure that Transmission Owners, Transmission Operators, and Transmission Planners have enough time to both design and implement any mitigation plans necessary to be compliant with the new language. In almost all cases the actual implementation of a solution requiring new construction will be dependent on a number of different regulatory agencies providing the necessary permits allowing for its construction. As such, NERC needs to ensure that any time frame associated with compliance to the proposed language be variable, and allow for extended implementation time frames based on system conditions that may delay placing mitigation plans in service. An example of a reasonable variable time frame to be compliant with the proposed language in footnote B would be to start the clock 60 months from receiving the pertinent environmental permitting. In
David Schiada	Southern California Edison Co.	3	Negative	
Ahmad Sanati	South California Edison Company	5	Negative	

Voter	Entity	Segment	Vote	Comment
				California this could be the issuance of a Draft Environmental Impact Review pursuant to the California Environmental Quality Act.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

The SDT has added more latitude for the Transmission Planner with the addition of the 3rd bullet and believes that 60 months should be sufficient.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

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- o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- o Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Henry Ernst-Jr	Duke Energy Carolina	3	Negative	On the initial ballot of TPL-001-1 Duke Energy also voted “Negative”, primarily because Duke believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We also sought rehearing on the Commission’s March 18 Order Setting Deadline for Compliance (Docket No. RM06-16), with respect to this and other issues. We believe that FERC’s directive in that Order to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for “reliable operation” of the bulk-power system to prevent “instability, uncontrolled separation or cascading failures,” none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission’s directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission’s reach beyond its review of measures that are needed for “reliable operation” of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission’s jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the potential impacts (environmental, historical, archaeological, aesthetic...) of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. With this “Negative” vote, Duke offers the following ideas on alternatives for the SDT to consider that will allow for appropriate discretion and facilitate proper planning while allowing non-consequential load loss (NCLL). The standard should allow for dropping of limited amounts of non-consequential load in situations where it would be reasonable for a bounded time period and under restricted system conditions (e.g. 1-3 years only when load is >90 % of peak conditions). Dropping of non-consequential load would be prudent planning in situations where the near term impact of load projections or implementation of nearby transmission/generation projects will alleviate the necessity of an upgrade to meet N-1 conditions. Also, reliability of service to end-use customer is impacted by the entire system

Voter	Entity	Segment	Vote	Comment
				from source to load. Where allowance for NCLL would not greatly impact individual end-use customers' level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to avoid projects without greatly impacting a customer's outage frequency and duration should be acceptable. Use of reliability metrics (e.g. SAIFI/SAIDI/ASAI) should also be considered by the SDT for determination of acceptable use of NCLL.
Luther E. Fair	Gainesville Regional Utilities	1	Affirmative	Even though I am voting in the affirmative, I agree that most of the comments offered by Duke and Norther Indiana in their earlier statements have merit and should be considered. Also, I believe that the use of reliability metrics should be considered by the SDT for determination of acceptable use of NCLL.
Mace Hunter	Lakeland Electric	3	Negative	Reliability should consider the entire system from source to load. Where allowance for NCLL would not greatly impact individual end-use customer's level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to delay projects without greatly impacting a customer's outage frequency and duration should be acceptable. Use of reliability metrics should also be considered by the SDT for determination of acceptable use of NCLL.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

The SDT discussed the use of reliability metrics for providing flexibility to planners but has not included their use as this would make the implementation too complex.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

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Sammy Roberts	Progress Energy Carolinas	1	Negative	Progress Energy applauds NERC's efforts to improve the footnote (b) language with respect to conditional allowance of curtailing Firm Transmission Service, which is addressed in the second paragraph of the proposed new footnote (b). PE remains concerned, however, that the first paragraph of the proposed new footnote (b) does not allow for curtailment of non-radial non-consequential load. The ability to curtail non-consequential load in the planning horizon can be a useful tool to mitigate local area issues, and has not been detrimental to the Bulk Electric System (BES). Disallowing the curtailment of non-radial non-consequential load essentially prohibits taking action in situations in which the load in question is clearly at a localized self-contained level of the system, i.e. the distribution system(s) served by the Transmission Owner. Prohibiting the curtailment of local load thus constitutes regulating distribution feeder reliability rather than BES reliability. Events that could be mitigated through the curtailment of local, non-radial non-consequential load are infrequent, and such curtailment has no material effect on the reliability of the BES. PE therefore suggests that the following addition (item (3)) to the first paragraph of the proposed footnote (b) be considered: "No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, and/or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities, and/or (3) Planned or controlled interruption of any additional Load required to mitigate the post-contingency results, provided that the non-
Lee Schuster	Florida Power Corporation	3	Negative	
Sam Waters	Progress Energy Carolinas	3	Negative	
Wayne	Progress Energy	5	Negative	

Voter	Entity	Segment	Vote	Comment
Lewis	Carolinas			consequential load being shed for the event is localized, and provided that the total load shed for the event does not exceed 2% of the Planned system peak demand or 200 MW, whichever value is less."

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. The SDT did adopt a limit but felt that 2% of system peak or 200 MW was not equitable for all entities.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

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Voter	Entity	Segment	Vote	Comment
Timothy VanBlaricom	California ISO	2	Negative	The California ISO supports NERC's request for a public technical conference to be held, as described in NERC's April 19, 2010 request for rehearing and motion for stay of the March 18 Order (RM06-16-009), to provide the opportunity to gain industry input and written comments regarding the Commission's TPL-002-0 directive for NERC to develop a modification to the TPL-002-0 Table 1 footnote b.

Response: The SDT agrees that a technical conference would be of value.

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td>Terry L. Blackwell</td><td>Santee Cooper</td><td>1</td><td>Negative</td><td rowspan="3">The Commission’s directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning processes appears to extend the Commission’s reach beyond its review of measures that are needed for “reliable operation” of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission’s jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. Table B footnote still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, and local customers should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. The Commission’s directive sets forth an expectation that NERC is to implement standards that address all loss of load at costs that may not be commensurate with bulk power system reliability, as statutorily defined, which is fundamentally different from what the Reliability Standards were intended to do.</td></tr>
<tr><td>Zack Dusenbury</td><td>Santee Cooper</td><td>3</td><td>Negative</td></tr>
<tr><td>Suzanne Ritter</td><td>Santee Cooper</td><td>6</td><td>Negative</td></tr>
<tr><td colspan="5">Response: The SDT is not in position to comment on FERC’s authority. The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.</td></tr>
<tr><td>Kimberly J. Jones</td><td>North Carolina Utilities Commission</td><td>9</td><td>Negative</td><td>The NC Utilities Commission is concerned that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1, and as explained in draft footnote b, is an inappropriate overreach into service issues that are more appropriately addressed by state regulatory commissions. This requirement does not provide any benefit to reliability of the bulk electric system and could undermine state efforts to balance reliability issues with cost of service issues. The standard should continue to allow Transmission Planners to use discretion regarding loss of non-consequential load, understanding that state commissions are positioned to force electric utilities to address local service quality issues on an expedited basis, should it be necessary and in the public interest.</td></tr>
<tr><td colspan="5">Response: The SDT understands the concern but believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Negative	THE PROPOSED INTERPRETATION WILL UNDERMINE THE INTERNATIONAL STANDARDS SETTING PROCESS AND COULD RESULT IN DIFFERING INTERPRETATIONS OF STANDARDS ON THE NORTH AMERICAN BULK-POWER SYSTEM.
Response: The SDT disagrees and believes that the footnote has been clarified appropriately within the standards development process.				
Daryn Barker	Louisville Gas and Electric Co.	6	Negative	The revised footnote b on Table 1 imposes additional requirements on the responsible entities. The footnote states: Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. However, R1 states: The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned These statements address different and inconsistent scope. If the change in scope was intended then a change should also be made to R1 to reconcile the inconsistency.
Charlie Martin	Louisville Gas and Electric Co.	5	Negative	Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. However, R1 states: The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned These statements address different and inconsistent scope. If the change in scope was intended then a change should also be made to R1 to reconcile the inconsistency.
Response: The SDT agrees that your assessment is for your portion of the interconnected grid. However, when performance in one system is dependent on generation dispatch in another system or vice versa, the SDT believes that one must ensure that the re-dispatch is feasible. The SDT does not believe that this presents a conflict with Requirement R1.				
John Apperson	PacifiCorp	3	Negative	This proposal warrants a "no" vote due to the current uncertainty regarding the outcome of the FERC TPL-002 NOPR issued by FERC on March 18, 2010. The impacts of the proposed changes to footnote B cannot be assessed separately from the alternative interpretation of TPL-002 proposed by FERC. The proper planning of a transmission system requires that all performance requirements are known and understood. If only some of the requirements are known and understood it is impossible to properly plan, study, assess, and operate the transmission system.

Voter	Entity	Segment	Vote	Comment
Response: The current TPL-002 is in force and will remain so until the completion of the cited FERC NOPR. This limited scope revision to footnote 'b' is to add clarity to what is in effect.				
Keith V. Carman	Tri-State G & T Association Inc.	1	Negative	Tri-State does believe that the new footnote is an improvement, but thinks there are still some changes necessary. We believe that the word "only" should be removed from the phrase "...where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities" because that discrimination was not required in FERC Order RM-06-16-009. There may be times when facilities near the temporary radial facilities might fall outside the limits set in reliability criteria but the situation is mitigated if the load shedding occurs at the radial facility. The meaning of the second paragraph of the new footnote is unclear. Tri-State recommends changing it to "Curtailment of Firm Transmission Service is not allowed unless it is coupled with curtailment-offsetting resources that are obligated to re-dispatch. Further, the curtailment activities cannot result in the shedding of any Firm load or in violations of Facility Ratings, either internal or external to the planning region." We believe that FERC's directive in FERC Order RM-06-16-009 to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load.
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. Instead of removing the word 'only', the 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.				

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The SDT is not in position to comment on FERC's authority. The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.</td></tr>
<tr><td>Claudiu Cadar</td><td>GDS Associates, Inc.</td><td>1</td><td>Negative</td><td>We do not agree with the proposed changes due to several reasons. Although the proposed change will directly influence the reliability standards and transmission system performances, will also have an indirect impact on the economic side with respect to the expansion of existing transmission system. We believe that FERC directive as stipulated in Order 693 cannot constrict, nor impose certain actions outside of the reliability limits. We believe that since these events are merely isolated and rarely enforced, the decision of mandating a great financial effort as a consequence of the proposed changes would certainly be counterbalanced by its feasibility when compare with the current cost of load shedding. While the revised footnote b can be certainly considered an improvement from the current version, however it still does not allow the joined entities involved to have power over the decision making when BES reliability is not an issue.

We also believe that any mandatory changes implemented in the TPL standards under the current scenario are not entirely feasible unless all other issues such as the definition of the</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
				BES, Consequential / Non-consequential Load, BES Critical Element, etc gets resolve ahead. The revision with respect to load shedding, specifically the portion about shedding loads on newly radial facilities, does not match the version 1 TPL standard definition of consequential load loss. To approve the proposed revision to footnote 'b' would create an unnecessary discrepancy between the version 1 TPL standard under consideration and the existing standards. We recognize that the Version 1 will replace Version 0, but since it appears that the performance standard with respect to footnote 'b' is intended to be same in the revised footnote and the Version 1 standard, it only makes sense that the revised version 0 footnote 'b' match the consequential load loss definition contemplated in Version 1. In the light of the above we suggest the Commission to approach different other solutions and ideas for improving the current reliability of the transmission system without enforcing decisions beyond its statutory scope. We advance an alternative to this matter meant to balance the reliability of the transmission system and its indirect financial impact. Although the solution that we offer would require an extended time for development and implementation, however we urge NERC to consider it in its further approach. Our alternative consists mainly in implementing an additional term such as "Critical Load" which we have briefly figured that would consist in particular load necessary to be maintained in service without interruption. Even though this new term would seemed to be at first related with the quality of the service, however a joint association of transmission planners, customers, regulatory entities as decision makers can simply individualize the load that cannot be shed, as well as future transmission improvements that will be required to serve this envisioned small amount of load rather than the entire load. In this way we will create a reasonable balance in between the reliability of the transmission system and the cost to maintain / improve this reliability.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

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The current TPL-002 is in force and will remain so for the forseeable future. This limited scope revision to footnote 'b' is to add clarity to what is in effect. Project 2006-02 is under revision and the clarifications of footnote 'b' will be considered by the SDT for future revisions of TPL-001-2. The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.				
Ronald D. Schellberg	Idaho Power Company	1	Negative	While the proposed revisions are an improvement to the prohibition on loss of non-consequential load for a single contingency proposed in the recently failed TPL-001-1 ballot, that the prohibition of loss of non-consequential load for events resulting the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. However, the removal of: "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers." will require significant adjustments in either TRM or TTC reductions to be compliant with this revised standard in the WECC Region. To construct additional transmission facilities to maintain present day business could easily exceed 10 Billion dollars throughout the WECC region. For example, the Pacific AC Intertie currently has a TTC of 4800 MW spread across 3 500 kV transmission lines. With the loss of one Transmission line, the Pacific AC intertie drops to 3200 MW. Removal of this sentence would require TP either to drop the Firm TTC of the Intertie to 3200, or include a TRM reservation of at least 1600 MW. The TPs would not be able to say that a loss of 1600 MW of import capacity would not result in curtailments of firm load. Just about all multi

Voter	Entity	Segment	Vote	Comment
				transmission line paths in the WECC Region would suffer. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. In the case of long interties between subregions of WECC, these interties have never been planned to operate in this manner. Idaho Power recommends that the sentence permiting system adjustments be reinserted into Footnote B.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

The SDT believes that System re-dispatch is an acceptable System adjustment to "remain within applicable Facility Ratings" to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can be only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the Firm Transmission Service cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW

Voter	Entity	Segment	Vote	Comment
o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.				
Francis J. Halpin	Bonneville Power Administration	5	Affirmative	For consistency, regarding the firm transfer issue, the term "Firm Transmission Service" should be replaced with "Firm Transfers" in order to be consistent with the fourth column of the existing Table 1 "Transmission System Standards - Normal and Emergency Conditions".
Response: The SDT agrees and has made the change. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.				
Kim Warren	Independent Electricity System Operator	2	Affirmative	IESO supports the revisions made to footnote 'b' based on the present definitions of BES and Firm Demand and on the understanding that the NERC standards apply only to the BES as defined in the NERC Glossary as follows: "As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighbouring systems, and associated equipment, generally operated at voltages of 100 kV

Voter	Entity	Segment	Vote	Comment
				or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition." To be clear, our interpretation of the present definition of BES is that it defers to each Regional Reliability Organization to define the elements of the power system that are considered BES and, therefore in the NPCC Region, "BES as defined by NERC" = "BPS as defined by NPCC".
Response: The SDT agrees that the standard applies to the BES as defined in the Glossary.				
Jacquie Smith	ReliabilityFirst Corporation	10	Affirmative	If this revision is an urgent action, then the implementation timeframe should be shorter. In the clarification paragraph below, I do not understand the first sentence. Are there commas missing? What is the requirement and what is the exception? Also, I question the validity of using "should" in the second sentence. If it is a requirement, then it needs to be stated as a requirement. If it is a suggestion, then it does not belong in the standard. No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.
Response: This has not been classified as an 'urgent action'. Commas have been added as appropriate and a re-wording was made which should make this clear. 'Should' has been replaced by 'would' to provide additional clarity. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels				

Voter	Entity	Segment	Vote	Comment
				greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
David H. Boguslawski	Northeast Utilities	1	Affirmative	Northeast Utilities (NU) believes the language of the proposed revision to footnote 'b' can be better defined as the proposed revision is subject to interpretation by the different entities and regulatory agencies. Future conflicts can be minimized by further clarifying the proposed revision. Also, NU is concerned that this new modification does not specify the amount of permissible load shed nor does it require the planning entity to minimize load shedding under this exception.

Response: The SDT has made several clarifying changes to the footnote which should alleviate your concerns.

The SDT has modified the footnote for clarity and added constraints in new bullet 3 to address your specific concern.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- o Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Donald S. Watkins	Bonneville Power Administration	1	Affirmative	On the firm transfer issues, the term "Firm Transmission Service" should be replaced with "Firm Transfers" to be consistent with the fourth column of the existing Table 1 Transmission System Standards - Normal and Emergency Conditions.
Rebecca Berdahl	Bonneville Power Administration	3	Affirmative	
Brenda S. Anderson	Bonneville Power Administration	6	Affirmative	

Response: The SDT agrees and has made this change.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Frank Gaffney	Florida Municipal Power Agency	4	Affirmative	Please see FMPA comments submitted through the concurrent comment period for Project 2010-11
David Schumann	Florida Municipal Power Agency	5	Affirmative	

Voter	Entity	Segment	Vote	Comment
Response: Please see the response to FMPA comments above.				
Carter B Edge	SERC Reliability Corporation	10	Affirmative	The footnote makes clearer when load can be dropped for planning purposes. By making this footnote more specific, it supports reliability and helps stakeholders apply the TPL standards.
Timothy Beyrle	City of New Smyrna Beach Utilities Commission	4	Affirmative	This is an area of fuzziness between State jurisdiction and Federal jurisdiction. In all honesty, shedding load for local area impacts has nothing to do with BES reliability and should not be under FERC jurisdiction under Section 215 of the Federal Power Act, but rather State jurisdiction for quality of service issues. However, there is also the matter of FERC jurisdiction over commercial matters and the opportunity to "game" the original footnote by transmission providers by allowing firm load shedding to grant firm transmission service for themselves, thereby avoiding or deferring transmission investment, while at the same time denying or requiring others to build the same transmission avoided in order to obtain transmission service. We can see how difficult it is from a drafting team's perspective in achieving a balanced position between these different matters. The drafting team should be applauded for finding a reasonable position.
Response: Thank you for your support.				
Larry E Watt	Lakeland Electric	1	Affirmative	This issue is better handled within the development of the new TPL-001 standard.
Response: The current TPL-002 is in force and will remain so until the completion of the TPL-001-2 effort. This limited scope revision to footnote 'b' is to add clarity to what is in effect.				

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Standards Authorization Request (SAR)
Ballot Pool and Pre-ballot Window (with Comment Period)
Project 2010-11: TPL Table 1, Footnote B

Now available at: http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

TPL Table 1, Footnote B SAR (Project 2010-11)

The Standards Committee, in response to a FERC Order issued March 18, 2010, has posted a proposed SAR, four draft standards, TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1, and an implementation plan, for a simultaneous pre-ballot review and 40-day comment period. The only change proposed in each of the four standards is to Table 1, Footnote 'b'.

The Order requires the ERO to file the revised standards by June 30. 2010. To meet this due date, the Standards Committee approved the following deviation from the standards development process:

- The proposed changes to the standards will be posted for a 40-day comment period. The Ballot Pool will be formed during the first 30 days of the 40-day comment period;
- The initial ballot will be conducted during the last 10 days of the 40-day comment period; and
- The drafting team may make modifications to the footnote between the initial and recirculation ballots based on stakeholder comments to improve the overall quality of the footnote.

Ballot Pool (through May 17, 2010)

Registered Ballot Body members may join the ballot pool to be eligible to vote on this interpretation **until 8 a.m. EDT on May 17, 2010**.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2010-11_TPL_SAR_in

Comment Period (through May 25, 2010)

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at 609-524-7047.

The status, purpose, a clean and redline version of the four standards, and supporting documents for this project — including an off-line, unofficial copy of the questions listed in the comment form — are posted at the following site: http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Project Background:

The Assess Transmission Future Needs Standard Drafting Team (Project 2006-02) has developed a clarification to TPL Table 1 — footnote 'b' concerning the loss of load and handling of firm transfers when a single contingency occurs on the transmission system.

The drafting team is proposing the following revision to footnote ‘b’: No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

On the firm transfer issue, the drafting team developed the following clarification:

No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions should also be respected.

Since this clarification may present a different interpretation of footnote ‘b’ than the one presently used by some entities, the SDT is proposing a 60 month implementation plan to allow those entities time to react.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Lauren Koller at Lauren.Koller@nerc.net

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Initial Ballot Window Open
May 17–27, 2010

Now available at: https://standards.nerc.net/CurrentBallots.aspx

TPL Table 1, Footnote B (Project 2010-11)
An initial ballot window for the TPL Table 1, Footnote B changes is now open **until 8 p.m. EST on May 27, 2010**.

The ballot includes four draft standards and an implementation plan. The only change proposed in each of the four standards (TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1) is to Table 1, Footnote 'b'.

Instructions
Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Next Steps
Voting results will be posted and announced after the ballot window closes.

Project Background
The Assess Transmission Future Needs Standard Drafting Team (Project 2006-02) has developed a clarification to TPL Table 1 — footnote 'b' concerning the loss of load and handling of firm transfers when a single contingency occurs on the transmission system.

The drafting team is proposing the following revision to footnote 'b': No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

On the firm transfer issue, the drafting team developed the following clarification:

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Since this clarification may present a different interpretation of footnote 'b' than the one presently used by some entities, the SDT is proposing a 60 month implementation plan to allow those entities time to react

Standards Development Process
The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Ballot Results	
Ballot Name:	Project 2010-11 SAR for TPL Table 1 Order_in
Ballot Period:	5/17/2010 - 5/27/2010
Ballot Type:	Initial
Total # Votes:	222
Total Ballot Pool:	263
Quorum:	84.41 % The Quorum has been reached
Weighted Segment Vote:	63.75 %
Ballot Results:	The standard will proceed to recirculation ballot.

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	77	1	36	0.59	25	0.41	1	15
2 - Segment 2.	10	0.7	5	0.5	2	0.2	1	2
3 - Segment 3.	58	1	30	0.566	23	0.434	2	3
4 - Segment 4.	13	1	7	0.636	4	0.364	1	1
5 - Segment 5.	49	1	25	0.641	14	0.359	0	10
6 - Segment 6.	36	1	17	0.63	10	0.37	3	6
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.3	2	0.2	1	0.1	1	3
9 - Segment 9.	5	0.3	1	0.1	2	0.2	1	1
10 - Segment 10.	8	0.7	6	0.6	1	0.1	1	0
Totals	**263**	**7**	**129**	**4.463**	**82**	**2.537**	**11**	**41**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Negative	View
1	Ameren Services	Kirit S. Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Jason Shaver	Affirmative	View
1	Associated Electric Cooperative, Inc.	John Bussman		
1	Avista Corp.	Scott Kinney		
1	BC Transmission Corporation	Gordon Rawlings	Negative	View
1	Beaches Energy Services	Joseph S. Stonecipher	Affirmative	

1	Black Hills Corp	Eric Egge	Negative	View
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy	Paul Rocha	Abstain	
1	Central Maine Power Company	Brian Conroy		
1	City of Vero Beach	Randall McCamish	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek		
1	Commonwealth Edison Co.	Daniel Brotzman	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Negative	View
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker	Negative	View
1	Dominion Virginia Power	John K Loftis	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	E.ON U.S. LLC	Larry Monday		
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	View
1	GDS Associates, Inc.	Claudiu Cadar	Negative	View
1	Georgia Transmission Corporation	Harold Taylor, II	Negative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Negative	View
1	Idaho Power Company	Ronald D. Schellberg	Negative	View
1	ITC Transmission	Elizabeth Howell		
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stan T. Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	View
1	Lee County Electric Cooperative	John W Delucca	Negative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	National Grid	Saurabh Saksena		
1	New York Power Authority	Arnold J. Schuff		
1	Northeast Utilities	David H. Boguslawski	Affirmative	View
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oncor Electric Delivery	Michael T. Quinn	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	View
1	Otter Tail Power Company	Lawrence R. Larson	Negative	View
1	Pacific Gas and Electric Company	Chifong L. Thomas	Negative	View
1	PacifiCorp	Mark Sampson	Negative	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	
1	Potomac Electric Power Co.	Richard J Kafka	Affirmative	View
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Negative	View
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Puget Sound Energy, Inc.	Catherine Koch	Affirmative	
1	San Diego Gas & Electric	Linda Brown	Affirmative	View
1	Santee Cooper	Terry L. Blackwell	Negative	View
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	South Texas Electric Cooperative	Richard McLeon	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Negative	View
1	Southern Company Services, Inc.	Horace Stephen Williamson	Negative	View
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Negative	View
1	Southwestern Power Administration	Gary W Cox		
1	Tennessee Valley Authority	Larry Akens	Affirmative	View
1	Tri-State G & T Association Inc.	Keith V. Carman	Negative	View
1	Tucson Electric Power Co.	John Tolo	Negative	View

1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Brandy A Dunn		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Transmission Corporation	Faramarz Amjadi	Negative	View
2	California ISO	Timothy VanBlaricom	Negative	View
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Affirmative	View
2	ISO New England, Inc.	Kathleen Goodman	Abstain	
2	Midwest ISO, Inc.	Jason L Marshall	Affirmative	
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Affirmative	
3	Alabama Power Company	Richard J. Mandes	Negative	View
3	Allegheny Power	Bob Reeping	Negative	
3	Ameren Services	Mark Peters	Affirmative	
3	American Electric Power	Raj Rana	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blue Ridge Power Agency	Duane S. Dahlquist	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	View
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	Cleco Utility Group	Bryan Y Harper	Abstain	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	David A. Lapinski	Negative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	View
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	W. R. Schoneck	Affirmative	View
3	Florida Power Corporation	Lee Schuster	Negative	View
3	Georgia Power Company	Anthony L Wilson	Negative	View
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Negative	
3	Great River Energy	Sam Kokkinen	Negative	
3	Gulf Power Company	Gwen S Frazier	Negative	View
3	Hydro One Networks, Inc.	Michael D. Penstone	Negative	View
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory David Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Negative	View
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Don Horsley	Negative	View
3	New York Power Authority	Marilyn Brown	Negative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	OTP Wholesale Marketing	Bradley Tollerson	Negative	
3	PacifiCorp	John Apperson	Negative	View
3	PECO Energy an Exelon Co.	Vincent J. Catania	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Negative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	Zack Dusenbury	Negative	View
3	Seattle City Light	Dana Wheelock	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young	Negative	View

3	Southern California Edison Co.	David Schiada	Negative	View
3	Tampa Electric Co.	Ronald L Donahey		
3	Wisconsin Electric Power Marketing	James R. Keller	Negative	
3	Xcel Energy, Inc.	Michael Ibold	Negative	View
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Affirmative	View
4	Consumers Energy	David Frank Ronk	Negative	View
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	View
4	Georgia System Operations Corporation	Guy Andrews	Negative	
4	Integrys Energy Group, Inc.	Christopher Plante		
4	Modesto Irrigation District	Spencer Tacke	Negative	View
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Avista Corp.	Edward F. Groce		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	View
5	City of Tallahassee	Alan Gale	Affirmative	View
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Affirmative	
5	Cleco Power LLC	Grant Bryant		
5	Conectiv Energy Supply, Inc.	Kara Dundas		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy	James B Lewis	Negative	View
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Robert Smith	Negative	
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Affirmative	View
5	Great River Energy	Cynthia E Sulzer	Negative	
5	JEA	Donald Gilbert	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin	Negative	View
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	
5	New York Power Authority	Gerald Mannarino	Negative	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	Otter Tail Power Company	Ward Uggerud	Negative	
5	PacifiCorp	Sandra L. Shaffer	Negative	
5	Portland General Electric Co.	Gary L Tingley		
5	PowerSouth Energy Cooperative	Tim Hattaway		
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Negative	View
5	PSEG Power LLC	David Murray	Affirmative	
5	RRI Energy	Thomas J. Bradish	Negative	View
5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	South California Edison Company	Ahmad Sanati	Negative	View
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	Tennessee Valley Authority	George T. Ballew	Affirmative	View
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Negative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		

5	Xcel Energy, Inc.	Liam Noailles	Negative	View
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Black Hills Corp	Tyson Taylor		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	View
6	Cleco Power LLC	Matthew D Cripps	Abstain	
6	Colorado Springs Utilities	John Mick	Negative	View
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas E Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell		
6	Great River Energy	Donna Stephenson	Negative	
6	Kansas City Power & Light Co.	Thomas Saitta	Negative	View
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker	Negative	View
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Negative	
6	OTP Wholesale Marketing	Bruce Glorvigen	Abstain	
6	Progress Energy	James Eckelkamp		
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Negative	View
6	RRI Energy	Trent Carlson	Negative	View
6	Santee Cooper	Suzanne Ritter	Negative	View
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	View
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8		James A Maenner	Negative	
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Abstain	
8	Montana Consumer Counsel	Lawrence P Nordell		
8	Power Energy Group LLC	Peggy Abbadini		
8	Shafer, Kline, & Warren Inc. (SKW)	Michael J Bequette, P.E.	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	California Energy Commission	William Mitchell Chamberlain	Negative	View
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson		
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	North Carolina Utilities Commission	Kimberly J. Jones	Negative	View
9	Oregon Public Utility Commission	Jerome Murray	Abstain	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Dan R. Schoenecker	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith	Affirmative	View
10	SERC Reliability Corporation	Carter B Edge	Affirmative	View
10	Western Electricity Coordinating Council	Louise McCarren	Negative	View

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Initial Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

TPL Table 1, Footnote B (Project 2010-11)

The initial ballot for TPL Table 1, Footnote B ended on May 27, 2010.

Ballot Results

Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 84.41 %
Approval: 63.75 %

Since at least one negative ballot included a comment, these results are not final. A second (or recirculation) ballot must be conducted. Ballot criteria are listed at the end of the announcement.

Next Steps

As part of the recirculation ballot process, the drafting team must draft and post responses to voter comments. The drafting team will also determine whether or not to make revisions to the balloted item(s). Should the team decide to make revisions, the revised item(s) will return to the initial ballot phase.

Project Background

The Assess Transmission Future Needs Standard Drafting Team (Project 2006-02) has developed a clarification to TPL Table 1 — footnote 'b' concerning the loss of load and handling of firm transfers when a single contingency occurs on the transmission system.

The drafting team is proposing the following revision to footnote 'b': No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

On the firm transfer issue, the drafting team developed the following clarification:

No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

Since this clarification may present a different interpretation of footnote 'b' than the one presently used by some entities, the SDT is proposing a 60 month implementation plan to allow those entities time to react

More information is available on the project page: http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Ballot Criteria

Approval requires both a (1) quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention, and (2) A two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and nonresponses. If there are no negative votes with reasons from the first ballot, the results of the first ballot shall stand. If, however, one or more members submit negative votes with reasons, a second ballot shall be conducted.

For more information or assistance,
please contact Lauren Koller at Lauren.Koller@nerc.net

Consideration of Comments on Project 2010-11: TPL Table 1 Order and Comments Submitted with Initial Ballots

The Standards Committee thanks all commenters who submitted comments on the proposed SAR for the TPL Table 1 Order. The SAR proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

The SAR, implementation plan, and the clean and redline versions to the four TPL standards were posted for a 40-day public comment period from April 15, 2010 through May 27, 2010. Stakeholders were asked to provide feedback on the standards through a special electronic comment form. There were 22 sets of comments, including comments from more than 80 different people from approximately 40 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

The initial ballot for the proposed changes to the four TPL standards was conducted from May 17-27, 2010. The comments submitted with initial ballots and the drafting team's responses to those comments are contained in this report.

All comments submitted during the comment period and the initial ballot results are posted on the following page:

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Based on stakeholder comments, the drafting team has made some additional changes to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT from the cited inputs that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when load could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote 'b' allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote 'b' were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand is appropriate in certain limited circumstances and that such usage is not widespread.
- Use of the term 'fringes' was seen as problematic and application at the 'fringes' could possibly be discriminatory.
- If interruption of non-consequential Demand were not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that requires ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote 'b'. This led to the approach shown in the 2nd posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote 'b' in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote 'b' to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

The above changes will be noted to stakeholders in a separate posting before the initiation of another ballot.

The revised Footnote 'b' is:

b) An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- Demand that is directly served by the elements that are removed from service as a result of the Contingency

- Interruptible Demand or Demand-Side Management

- Demand that does not adversely impact overall BES reliability where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

If you feel that your comment has been overlooked, 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]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Comments and Responses from Formal Comment Period:

Comments and Responses from Initial Ballot:

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, 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, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
4.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
5.	Sylvain Clermont	Hydro-Quebec TransEnergie		1
6.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
7.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
8.	Ben Eng	New York Power Authority	NPCC	4
9.	Brian Evans-Mongeon	Utility Services	NPCC	8
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
11.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
12.	Kathleen Goodman	ISO - New England	NPCC	2
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1
14.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
15.	Randy MacDonald		New Brunswick System Operator	NPCC					2				
16.	Bruce Metruck		New York Power Authority	NPCC					6				
17.	Lee Pedowicz		Northeast Power Coordinating Council	NPCC					10				
18.	Robert Pellegrini		The United Illuminating Company	NPCC					1				
19.	Saurabh Saksena		National Grid	NPCC					1				
20.	Michael Schiavone		National Grid	NPCC					1				
2.	Group	Philip R. Kleckley	South Carolina Electric & Gas	X		X		X					
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Bob Jones		Southern Company Services - Trans.	SERC					1				
2.	David Marler		Tennessee Valley Authority	SERC					1				
3.	Charles Long		Entergy	SERC					1				
4.	James Manning		North Carolina Electric Membership Corporation	SERC					3				
5.	Pat Huntley		SERC Reliability Corporation	SERC					10				
3.	Group	John Bee	Exelon Transmission Strategy & Compliance	X		X		X					
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Mortenson, Eric		:(ComEd)	RFC					1				
2.	Weaver, David W		(PECO)	RFC					1				
3.	McHugh, Kathleen P		(PECO)	RFC					1				
4.	Kay, Thomas W		(ComEd)	RFC					1				
5.	Szymczak, Ronald		(ComEd)	RFC					1				
6.	Chu, Ron F		(PECO)	RFC					1				
7.	Donnelly, Michael J		(PECO)	RFC					1				
8.	Kliros, Chris B		(ComEd)	RFC					1				
9.	Mills, Paul M		(ComEd)	RFC					1				
10.	Webb, Becky		(ComEd)	RFC					1				
4.	Group	Denise Koehn	BPA, Transmission Reliability Program	X		X		X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

Additional Member	Additional Organization	Region	Segment Selection
1. Chuck Matthews	BPA, Transmission Planning	WECC	1
2. Berhanu Tesema	BPA, Transmission Planning	WECC	1
3. Larry Furumasu	BPA, Transmission Planning	WECC	1
4. Kyle Kohne	BPA, Transmission Planning	WECC	1
5. Don Watkins	BPA, Transmission System Operations	WECC	1
6. Rebecca Berdahl	BPA, Power, Long Term Sales and Purchases	WECC	3

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Carol Gerou	Midwest Reliability Organization										X

Additional Member	Additional Organization	Region	Segment Selection
1. Chuck Lawrence	American Transmission Company	MRO	1
2. Tom Webb	Wisconsin Public Service	MRO	3, 4, 5, 6
3. Terry Bilke	Midwest ISO Inc.	MRO	2
4. Jodi Jenson	Western Area Power Administration	MRO	1, 6
5. Ken Goldsmith	Alliant Energy	MRO	4
6. Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
7. Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
8. Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
9. Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
10. Scott Nickels	Rochester Public Utilities	MRO	4
11. Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Richard Kafka	Pepco Holdings, Inc.	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Jim Summers	Delmarva Power and Light Co.	RFC	1
2. John Radman	Potomac Electric Power Company	RFC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Ben Li	IESO		X								

Additional Member	Additional Organization	Region	Segment Selection

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Bill Phillips		MISO	MRO									
2.	James Castle		NYISO	NPCC									
3.	Charles Yeung		SPP	SPP									
4.	Lourdes Estrada-Salinero		CAISO	WECC									
5.	Patrick Brown		PJM	RFC									
6.	Steve Myers		ERCOT	ERCOT									
8.	Group	Frank Gaffney	Florida Municipal Power Agency	X			X	X	X				
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Timothy Beyrle		Utilities Commission of New Smyrna Beach	FRCC					4				
2.	Greg Woessner		Kissimmee Utility Authority	FRCC					1				
3.	Jim Howard		Lakeland Electric	FRCC					1				
4.	Lynne Mila		City of Clewiston	FRCC					3				
5.	Joe Stonecipher		Beaches Energy Services	FRCC					1				
6.	Cairo Vanegas		Fort Pierce Utility Authority	FRCC					4				
9.	Individual	Stephen Mizelle	Southern Company Transmission	X									
10.	Individual	Robert Casey	Georgia Transmission Corporation (Bulk System Planning)	X									
11.	Individual	Thad Ness	American Electric Power	X		X		X	X				
12.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
13.	Individual	Martin Bauer	US Bureau of Reclamation					X					
14.	Individual	Kirit Shah	Ameren	X		X		X	X				
15.	Individual	Robert W. Roddy	Dairyland Power Cooperative	X		X		X					

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
16.	Individual	Marty Berland	Progress Energy	X		X		X	X				
17.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X					
18.	Individual	Charles Lawrence	American Transmission Company	X									
19.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
20.	Individual	Bill Middaugh	Tri-State Generation and Transmission Association, Inc.	X		X		X	X				
21.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									
22.	Individual	Dan Rochester	Independent Electricity System Operator		X								

1. **The SDT is proposing a revision to footnote ‘b’ in the TPL tables to comply with FERC Order RM-06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote ‘b’, regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system by June 30, 2010. Do you agree with the proposed changes and if not, please provide specific reasons for your disagreement.**

Summary Consideration: The SDT has listened to the comments from the industry, understands the concerns raised, and has made changes to the footnote to balance the various industry concerns while assuring BES reliability.

Stakeholders identified that the terminology used in Footnote ‘b’ didn’t match the terminology used in the associated column heading of Table 1 – ‘Loss of Demand or Curtailed Firm Transfers.’ For additional clarity, the team made the following terminology changes:

- The term ‘Load’ was replaced with ‘Demand’
- The term ‘Firm Transmission Service’ was replaced with ‘firm transfers’

While the initial ballot results came close to the required approval percentage, it was clear to the SDT from the cited inputs that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when load could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn’t been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term 'fringes' was seen as problematic and application at the 'fringes' could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote 'b'. This led to the approach shown in this 2nd posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote 'b' in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote 'b' to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial~~

~~Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Duke Energy	No	Duke Energy voted "Negative" on the initial and current ballots of TPL-001-1, primarily because Duke believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We also sought rehearing on the Commission's March 18 Order Setting Deadline for Compliance (Docket No. RM06-16), with respect to this and other issues. We believe that FERC's directive in that Order to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the potential impacts (environmental, historical, archaeological, aesthetic...) of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. Duke offers the following ideas on alternatives for the SDT to consider that will allow for appropriate discretion and facilitate proper planning while allowing non-consequential load loss (NCLL).The standard should allow for dropping of limited amounts of non-consequential load in situations where it would be reasonable for a

Organization	Yes or No	Question 1 Comment
		bounded time period and under restricted system conditions (e.g. 1-3 years only when load is >90 % of peak conditions). Dropping of non-consequential load would be prudent planning in situations where the near term impact of load projections or implementation of nearby transmission/generation projects will alleviate the necessity of an upgrade to meet N-1 conditions. Also, reliability of service to end-use customer is impacted by the entire system from source to load. Where allowance for NCLL would not greatly impact individual end-use customers' level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to avoid projects without greatly impacting a customer's outage frequency and duration should be acceptable. Use of reliability metrics (e.g. SAIFI/SAIDI/ASAI) should also be considered by the SDT for determination of acceptable use of NCLL.
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Midwest Reliability Organization	No	For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by

Organization	Yes or No	Question 1 Comment
		the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.
Dairyland Power Cooperative	No	DPC concurs with the MRO comments: For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.
American Transmission Company	No	For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.

Response: The SDT has added the second bullet to address your concern.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Georgia Transmission Corporation (Bulk System Planning)	No	Georgia Transmission Corporation (GTC) believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We believe that FERC's directive in (Docket No. RM06-16) to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. We also note that on April 19 NERC filed a request for rehearing with FERC asking that the Commission revise the directive in Paragraph 8 of the March 18 TPL-002 Order to allow NERC the necessary time to incorporate changes to the TPL-002 Reliability Standard through the Reliability Standards Development Process that are necessary to achieve bulk power system reliability. NERC also requested that the Commission grant NERC's Motion for Stay to stay the Order so that a public technical conference with opportunity for comment can be held in order to provide parties an opportunity to meet and discuss the technical considerations of developing a modification to the TPL-002 standard that prohibits the loss of non-consequential firm load in the event of an N-1 contingency. NERC's April 19 filing pointed out that if the Commission's directive to disallow the loss of non-consequential firm load for an N-1 contingency is implemented, a question is presented regarding whether the Reliability Standard still serves the purpose of ensuring the Reliable Operation of the bulk power system by preventing instability, uncontrolled separation, and cascading failures. That is, the Commission's directive sets forth an expectation that NERC is to implement standards that address all loss of load at costs that may not be commensurate with bulk power system reliability, as statutorily defined, which is fundamentally different from what the Reliability Standards were intended to do.
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the		

Organization	Yes or No	Question 1 Comment
various industry concerns while assuring BES reliability. . Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Progress Energy	No	Progress Energy applauds NERC's efforts to improve the footnote (b) language with respect to conditional allowance of curtailing Firm Transmission Service, which is addressed in the second paragraph of the proposed new footnote (b). PE remains concerned, however, that the first paragraph of the proposed new footnote (b) does not allow for curtailment of non-radial non-consequential load. The ability to curtail non-consequential load in the planning horizon can be a useful tool to mitigate local area issues, and has not been detrimental to the Bulk Electric System (BES). Disallowing the curtailment of non-radial non-consequential load essentially prohibits taking action in situations in which the load in question is clearly at a localized self-contained level of the system, i.e. the distribution system(s) served by the Transmission Owner/Operator. Prohibiting the curtailment of local load thus constitutes regulating distribution feeder reliability rather than BES reliability. Events that could be mitigated through the curtailment of local, non-radial non-consequential load are infrequent, and such curtailment has no material effect on the reliability of the BES.

Organization	Yes or No	Question 1 Comment
		PE therefore suggests that the following addition (item (3)) to the first paragraph of the proposed footnote (b) be considered:"No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, and/or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities, and/or (3) Planned or controlled interruption of any additional Load required to mitigate the post-contingency results, provided that the non-consequential load being shed for the event is localized, and provided that the total load shed for the event does not exceed 2% of the Planned system peak demand or 200 MW, whichever value is less."

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The SDT did not adopt numerical limits as a single nation-wide value was not seen as equitable for all entities.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Hydro-Québec TransEnergie	No	The proposed changes do not adequately address FERC's concerns in RM06-16-009. The Commission

Organization	Yes or No	Question 1 Comment
(HQT)		again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is “based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios.” The proposed changes to footnote ‘b’ indicate “No interruption of firm Load is allowed except:... (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.” The exception described appears to still allow non-consequential load loss. FERC describes in RM06-16-009 non-consequential load loss as “the removal, by any means, of any firm load that is not directly served by the elements that are removed from service as a result of the contingency.” In referencing Order 693, the Commission reiterated its position that TPL standards “should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency.” ”Must” should be used instead of “should” in the last sentence of the footnote, making it to read “Facility Ratings in those regions must also be respected.”
Northeast Power Coordinating Council	No	The proposed changes do not adequately address FERC’s concerns in RM06-16-009. The Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is “based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios.” The proposed changes to footnote ‘b’ indicate “No interruption of firm Load is allowed except:... (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.” The exception described appears to still allow non-consequential load loss. FERC describes in RM06-16-009 non-consequential load loss as “the removal, by any means, of any firm load that is not directly served by the elements that are removed from service as a result of the contingency.” In referencing Order 693, the Commission reiterated its position that TPL standards “should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency.” ”Must” should be used instead of “should” in the last sentence of the footnote, making it to read “Facility Ratings in those regions must also be respected.”
Response: The SDT believes that it has been responsive to the FERC directive in that the standards development process has been employed. In the development of the footnote, the SDT has balanced the need for discretion while addressing local area concerns with the need to assure the reliability of the BES.		

Organization	Yes or No	Question 1 Comment
'Must' is not appropriate in a footnote as it would impose a requirement in the footnote. The SDT has replaced 'should' with 'would' to correct the grammar. Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Tri-State Generation and Transmission Association, Inc.	No	Tri-State does believe that the new footnote is an improvement, but thinks there are still some changes necessary. We believe that the word "only" should be removed from the phrase "...where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities" because that discrimination was not required in FERC Order RM-06-16-009. There may be times when facilities near the temporary radial facilities might also fall outside the limits set in reliability criteria but the situation is mitigated if the load shedding occurs at the radial facility. The meaning of the second paragraph of the new footnote is unclear. Tri-State recommends changing it to "Curtailment of Firm Transmission Service is not allowed unless it is coupled with curtailment-offsetting resources that are obligated to re-dispatch. Further, the curtailment activities cannot result in the shedding of any Firm load or in violations of Facility Ratings, either internal or external to the planning region."
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the		

Organization	Yes or No	Question 1 Comment
various industry concerns while assuring BES reliability. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others. Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Southern Company Transmission	No	We propose that the section in double parentheses be deleted. The proposed wording by the drafting team seems to imply that the curtailment of firm transmission service is permitted to address single contingency constraints if coupled with the redispatch of network resources. The original language stated only that curtailments were permitted to prepare for the next contingency, not to address loading related to the initial contingency. The proposed wording could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint. Southern Companies recommend that the original language relating to "preparing for the next contingency" be incorporated into the drafting team's proposal.((Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including

Organization	Yes or No	Question 1 Comment
		curtailments of contracted Firm (non-recallable reserved) electric power Transfers.)) No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch. where it can It must be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

Response: The SDT believes that System re-dispatch is an acceptable System adjustment to "remain within applicable Facility Ratings" to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the firm transfers cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
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South Carolina Electric & Gas	Yes	For better clarity delete the phrase "when coupled with" in the second paragraph of footnote 'b.'
Response: The SDT did not delete the suggested phrase as it believes it is correct as stated but added commas to make the phrase read more clearly. Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Independent Electricity System Operator	Yes	IESO supports the revisions made to footnote 'b' based on the present definitions of BES and Firm Demand and on the understanding that the NERC standards apply only to the BES as defined in the NERC Glossary as follows:"As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition." To be clear, our interpretation of the present definition of BES is

Organization	Yes or No	Question 1 Comment
		that it defers to each Regional Reliability Organization to define the elements of the power system that are considered BES and, therefore in the NPCC Region, "BES as defined by NERC" = "BPS as defined by NPCC".
Response: The SDT agrees that the standard applies to the BES as defined in the Glossary.		
BPA, Transmission Reliability Program	Yes	On the firm transfer issues, the term "Firm Transmission Service" should be replaced with "Firm Transfers" to be consistent with the fourth column of the existing Table 1 Transmission System Standards - Normal and Emergency Conditions.
Response: The SDT agrees and has made the change. Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
American Electric Power	Yes	

Organization	Yes or No	Question 1 Comment
Exelon Transmission Strategy & Compliance	Yes	
Florida Municipal Power Agency	Yes	
IESO	Yes	
Northeast Utilities	Yes	
Pepco Holdings, Inc.	Yes	
US Bureau of Reclamation	Yes	
Manitoba Hydro	Yes	MH agrees with the SDT proposal.
Ameren	Yes	We were ok with the previous language. Though we do not intend to drop non-consequential load for a single contingency, we undersatnd that other ares may have been following such practice without degarding the relaibility of BES. We believe that they can continue this practice if they develop non-firm contracts with these customers.
Response: Thank you for your support. Several stakeholders proposed additional modifications and the drafting team did make several additional modifications to the footnote – please see the revised footnote.		

2. Are you aware of any conflicts caused by compliance with the proposed language in Table 1 — footnote b and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement? If yes, please identify the conflict.

Summary Consideration: The SDT understands that there may be conflicts as pointed out by respondents; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES. Strict numerical constraints applied across all of North America were not seen as appropriate. Instead, the SDT is leveraging existing processes to require documentation of Demand to be interrupted including alternatives evaluated and for the situation to be vetted in an open and transparent stakeholder process.

Footnote ‘b’ now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 2 Comment
Ameren	No	

Organization	Yes or No	Question 2 Comment
American Electric Power	No	
American Transmission Company	No	
BPA, Transmission Reliability Program	No	
Dairyland Power Cooperative	No	
Exelon Transmission Strategy & Compliance	No	
Independent Electricity System Operator	No	
Manitoba Hydro	No	
Midwest Reliability Organization	No	
Southern Company Transmission	No	
US Bureau of Reclamation	No	
South Carolina Electric & Gas	No	The comments expressed herein represent a consensus of the views of the above named members of the SERC Engineering Committee Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.
Response: Thank you for your response. Several stakeholders proposed additional modifications and the drafting team did make several additional modifications to the footnote – please see the revised footnote.		
Hydro-Québec TransEnergie (HQT)	Yes	Conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC’s position on non-consequential load loss. State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict

Organization	Yes or No	Question 2 Comment
		between state and federal positions could place utilities in a compromising position.
Northeast Power Coordinating Council	Yes	Conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.
IESO	Yes	It should be noted that conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. In RM-06-16-009, the Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." In the US, State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.Similar conflicts may also exist in Canada.
Progress Energy	Yes	There is the potential for conflict between Table 1 - Footnote (b) as currently proposed, which can be considered to regulate local distribution reliability without improving BES reliability, and local service reliability issues which are under the purview of state regulatory agencies. For example, the North Carolina Utilities Commission (NCUC) commented regarding this concern in the ballot which ended March 1 in Project 2006-02. Specifically, NCUC commented that they were "...concerned that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1 is an inappropriate overreach into service issues that are more appropriately addressed by state regulatory commissions..." Progress Energy believes that NCUC's concerns are legitimate. BES reliability should address the avoidance and mitigation of cascading outages and BES facility damage, rather than limited, controlled local area loss of load, in order to avoid this conflict and overlap of regulation.
Response: The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES. Strict numerical constraints applied across all of North America were not seen as appropriate. Instead, the SDT is leveraging existing processes to require documentation of Demand to be interrupted including alternatives evaluated and for the situation to be vetted in an open and transparent stakeholder process.		

Organization	Yes or No	Question 2 Comment
Northeast Utilities	Yes	Northeast Utilities (NU) believes the language of the proposed revision to footnote ‘b’ can be better defined as the proposed revision is subject to interpretation by the different entities and regulatory agencies. Future conflicts can be minimized by further clarifying the proposed revision. Also, NU is concerned that this new modification does not specify the amount of permissible load shed nor does it require the planning entity to minimize load shedding under this exception.
Response: The SDT has made several clarifying changes to the footnote which should alleviate your concerns. Footnote ‘b’ now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Duke Energy	Yes	See response to question #1.
Georgia Transmission Corporation (Bulk System Planning)	Yes	See response to Question #1.

Organization	Yes or No	Question 2 Comment
Response: See response to question #1.		
Florida Municipal Power Agency	Yes	This is an area of fuzziness between State jurisdiction and Federal jurisdiction. In all honesty, shedding load for local area impacts has nothing to do with BES reliability and should not be under FERC jurisdiction under Section 215 of the Federal Power Act, but rather State jurisdiction for quality of service issues. However, there is also the matter of FERC jurisdiction over commercial matters and the opportunity to “game” the original footnote by transmission providers by allowing firm load shedding to grant firm transmission service for themselves, thereby avoiding or deferring transmission investment, while at the same time denying or requiring others to build the same transmission avoided in order to obtain transmission service. We can see how difficult it is from a drafting team’s perspective in achieving a balanced position between these different matters. The drafting team should be applauded for finding a reasonable position.
Pepco Holdings, Inc.	Yes	This is not an issue for historic PJM members, but as PJM has expanded and as a result of the merger of historic councils into RFC, I am aware that not all regions had standards equal to those of MAAC, and this has been an issue worked out between transmission planners (historic transmission owners) and their local regulators. It is ultimately a cost issue for loss of local load that does not affect the overall reliability of the interconnected BES.
Response: Thank you for your support.		
Tri-State Generation and Transmission Association, Inc.	Yes	We believe that FERC’s directive in FERC Order RM-06-16-009 to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for “reliable operation” of the bulk-power system to prevent “instability, uncontrolled separation or cascading failures,” none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission’s directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission’s reach beyond its review of measures that are needed for “reliable operation” of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission’s jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load.
Response: The SDT is not in a position to comment on FERC’s authority. The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES. Such constraints would be determined through the open and transparent stakeholder process.		

3. Consideration of Comments on Initial Ballot — TPL Table 1 Order (Project 2010-11) May 17–27, 2010

Summary Consideration: The SDT has listened to the comments from the industry, understands the concerns raised, and has made changes to the footnote to balance the various industry concerns while assuring BES reliability.

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT from the cited inputs that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when load could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote 'b' allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote 'b' were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could

you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this 2nd posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that likely will be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

Footnote ‘b’ now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~

o Interruptible Demand or Demand-Side Management

o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Rodney Phillips	Allegheny Power	1	Negative	Allegheny Power believes the loss of non-consequential load and/or curtailment of transmission service for N-1 contingencies should be limited to only extreme circumstances. Exception 2 of footnote b allows for the loss of non-consequential load for N-1 contingencies with no restriction. Allegheny Power recommends removing exception 2 footnote b.
Response: The SDT and the majority of the commenters disagree with this suggestion.				
Gordon Rawlings	BC Transmission Corporation	1	Negative	BCTC appreciates the good work of the SAR committee in drafting the changes to Footnote b of Table 1. BCTC agrees with the drafting team that interruption of firm load, served by either radial circuits or circuits that have became radial as a result of the contingency, should be allowed for N-1 contingencies. However, it is our position that interruption of firm load should not be limited only to such consequential loads. In our view, interruption of electric supply to some local network customers in the affected area should be permissible. This inclusion will allow transmission planners to plan BCTC's regional transmission network reliably and without impacting neighbouring transmission networks.
Faramarz Amjadi	BC Transmission Corporation	2	Negative	
Hubert C. Young	South Carolina Electric & Gas Co.	3	Negative	SCE&G has significant concern with the proposed revision to TPL Table 1, Footnote B. The current Footnote B states "Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted

Voter	Entity	Segment	Vote	Comment
				element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems". The phrase "without impacting the overall reliability of the interconnected transmission systems" is important to the TPL standards to ensure that ERO standards do not dictate the level of service to customers. Service to customers and load pockets is jurisdictional to State Commissions and ERO standards should not compromise this jurisdiction. SCE&G believes that any proposed revisions to Footnote B must retain the concept that planned or controlled interruption of electric supply to customers, whether they are radial or network, is allowed as long as it does not impact the overall reliability of the interconnected transmission systems. The proposed revision eliminates this concept. There seems to be a general inconsistency and maybe confusion between the terms "reliability" and "level of service".
David Frank Ronk	Consumers Energy	4	Negative	The current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the previous version of TPL-001-1. However, it still does not allow Transmission Planners to use appropriate and necessary discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should control the decision making when BES reliability is not an issue. Often, the consequences of these events are solely local in nature, requiring only minor additional loss of local load to avoid the costly major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load.
James B Lewis	Consumers Energy	5	Negative	
Hugh A. Owen	Public Utility District No. 1 of Chelan County	6	Negative	The interruption of a small amount of load is, under most conditions, not a risk to the reliability of the BES and is at times necessary to preserve reliability. The planned interruption of some load may be a cost effective alternative to a costly transmission project. That is a quality of service issue.
Michael Gammon	Kansas City Power & Light Co.	1	Negative	While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit
Charles Locke	Kansas City Power & Light Co.	3	Negative	
Thomas Saitta	Kansas City Power & Light Co.	6	Negative	

Voter	Entity	Segment	Vote	Comment
				point of view to allow loss of non-consequential load.
Linda Brown	San Diego Gas & Electric	1	Affirmative	As to item (1), all load served directly by a transmission element which experiences a fault will be interrupted when the faulted element is taken out of service. This is the natural relationship between the load and the transmission element. Allowing this for BES elements may encourage transmission owners to remove transmission instead of upgrading or replacing it. Consider a load supplied by two transmission lines of different capacity. If the larger line is lost due to a contingency (N-1) and the remaining smaller line overloads the transmission owner is left with several options to address the problem: (1) move load between buses, (2) upgrade the smaller line, (3) add another line, or (4) create a radial load by removing the smaller line. Number (4) may be the least expensive and allowable under TPL-002, footnote b. Item (2) may also encourage transmission owners to develop plans which make load shedding part of category B. Consider a load served by three transmission lines, a utility may decide to remove a line, instead of upgrading, in order to set up a situation where an N-1 contingency would make the bus temporarily radial. In the event of a single outage (N-1), the load bus will be temporarily radial and load can be shed at the bus.
W. R. Schoneck	Florida Power & Light Co.	3	Affirmative	I believe the language is an improvement and clarifies the intent but I believe there still should be additional language added to give an exemption in meeting this requirement if it does not make economic sense(not economically feasible) and has no real impact on the BES.
Richard J Kafka	Potomac Electric Power Co.	1	Affirmative	It is understood that this is a compliance filing issue. This is not an issue for historic PJM members, but as PJM has expanded and as a result of the merger of historic councils into RFC, I am aware that not all regions had standards equal to those of MAAC, and this has been an issue worked out between transmission planners (historic transmission owners) and their local regulators. It is ultimately a cost issue for loss of local load that does not affect the overall reliability of the interconnected BES.
Alan Gale	City of Tallahassee	5	Affirmative	TAL thanks for SDT for the tireless effort to get to this point. TAL is voting affirmative with the following comments. We accept that the loss of non-consequential load is not a desired result for N-1 contingencies. It is also not the norm in system planning or operations. The flexibility to operate the system consistent with “good utility practice” may warrant the “odd-ball” case that would require this to occur. The dropping of non-consequential load

Voter	Entity	Segment	Vote	Comment
				will NOT lead to BES instability, voltage collapse, or cascading outages, which is what FERC and NERC are charged with preventing. It will lead to the shedding of load in a local area only. Utilities do not drop customers lightly. If the meter isn't turning, we are not getting paid, so we want the meter spinning. Utility power, while vital to our normal day-to-day lives and infrastructure, was never intended to be without interruption.
Brad Chase	Orlando Utilities Commission	1	Affirmative	This change raises the bar on transmission system performance. This change applies a blanket requirement upon entities that does not take into account the number of outages, probability of outages or cost to the customer. There are certain to be situations where this blanket requirement will result in increased cost to customers for no noticeable increase in reliability. OUC does agree with the concept of greater clarification on this requirement, however this clarification may raise the bar to far by trying to establish a blanket requirement. Duke, Progress Energy and others will be submitting comments with proposed language that attempt to address some of these issues and we encourage the drafting team to consider those comments.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of

Voter	Entity	Segment	Vote	Comment
				resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Eric Egge	Black Hills Corp	1	Negative	Black Hills believes that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
Chifong L. Thomas	Pacific Gas and Electric Company	1	Negative	PG&E commends the SDT for developing the proposed footnote b. While it is a great improvement over the complete prohibition on loss of non-consequential load for any single contingency, the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system, especially where the impact is local in nature, to avoid instability, cascading or uncontrolled separation. Such planned interruption of load may be a reasonable alternative to the environmental impacts or prohibitive costs associated with a major new transmission project. Given the potential impacts of the proposed modification, further vetting of the issues is needed. PG&E believes that NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.

Voter	Entity	Segment	Vote	Comment
Thomas J. Bradish	RRI Energy	5	Negative	RRI supports the WECC position on this issue; namely, that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
Trent Carlson	RRI Energy	6	Negative	
John Tolo	Tucson Electric Power Co.	1	Negative	The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project.
James Tucker	Deseret Power	1	Negative	The prohibition of loss of non-consequential load for events resulting the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including

Voter	Entity	Segment	Vote	Comment
				customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
Louise McCarren	Western Electricity Coordinating Council	10	Negative	The proposed revisions to footnote b of Table 1 are an improvement to the recently balloted prohibition on loss of non-consequential load for single contingencies. The recognition of the new term "temporarily radial" is a step in the right direction. However, the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
William Mitchell Chamberlain	California Energy Commission	9	Negative	While the proposed revisions to footnote b are an improvement to the prohibition on loss of non-consequential load for a single contingency proposed in the recently failed TPL-001-1 ballot, the prohibition of loss of non-consequential load for events resulting the loss of a single element still inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is

Voter	Entity	Segment	Vote	Comment
				local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
John Mick	Colorado Springs Utilities	6	Negative	Colorado Springs Utilities ballot on the proposed changes to TPL Table 1, footnote b directed in FERC Order RM06-16-009 Colorado Springs Utilities wishes to vote NO on the proposed changes to TPL Table 1, footnote b, directed in FERC Order RM06-16-009. CSU concurs with the WECC position paper for the ballot, and agrees with the WECC statement "that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues".

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

The SDT agreed that a technical conference on this issue would be of value and held such a conference on August 10, 2010.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and

Voter	Entity	Segment	Vote	Comment
				~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Horace Stephen Williamson	Southern Company Services, Inc.	1	Negative	Comments have already been submitted previously, but it will be added here again. Proposed footnote should read... No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers when coupled with the appropriate re-dispatch of resources obligated to re-dispatch. It must be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. The proposed changes are based on the following... "The proposed wording by the drafting team seems to imply that the curtailment of firm transmission service is permitted to address single contingency constraints if coupled with the redispatch of network resources. The original language stated only that curtailments were permitted to prepare for the next contingency, not to address loading related to the initial contingency. The proposed wording could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint. Southern Companies recommend that the original language relating to "preparing for the next contingency" be incorporated into the drafting team's proposal."
Richard J. Mandes	Alabama Power Company	3	Negative	
Anthony L Wilson	Georgia Power Company	3	Negative	
Gwen S Frazier	Gulf Power Company	3	Negative	
Don Horsley	Mississippi Power	3	Negative	
Michael Ibold	Xcel Energy, Inc.	3	Negative	The proposed modification to footnote b of Table I in TPL-001 - 004 standards states that after a Category B contingency, there should not be any thermal, voltage or stability violation, no interruption of firm load (except the load that is directly connected to the elements that are removed from service as a result of the contingency) and no firm transfer curtailment (except when coupled with re-dispatch of resources obligated to re-dispatch). We believe the proposed footnote b creates a gap between TPL-002 and TPL-003 standards, since it does not address conditions when firm load shedding and firm transfer curtailments are not required to meet the system performance for Category B contingency, but one or both are the required system adjustments to prepare for the next contingency (Category C3). When firm transfer is curtailed after the first contingency in
Liam Noailles	Xcel Energy, Inc.	5	Negative	
David F. Lemmons	Xcel Energy, Inc.	6	Negative	

Voter	Entity	Segment	Vote	Comment
				preparation for the next contingency, it is not clear from the proposed footnote b if this is considered a valid system adjustment for Category C or a violation of Category B. Recall that the existing footnote b addresses this condition explicitly by stating "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm Transfers."
George T. Ballew	Tennessee Valley Authority	5	Affirmative	TVA appreciates the work of the SDT on this issue. However, TVA recommends revising the second paragraph of the revised footnote b: "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. However, curtailment of Firm Transmission Service is only allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected." Without the changes in the first two sentences above, the proposed wording by the SDT could be interpreted to allow re-dispatch/firm curtailments to address any single contingency constraint instead of in preparation for the next contingency.
Marjorie S. Parsons	Tennessee Valley Authority	6	Affirmative	
Larry Akens	Tennessee Valley Authority	1	Affirmative	TVA appreciates the work of the SDT. However, TVA recommends revising the second paragraph of the revised footnote "b". Without changes in the first two sentences, the proposed wording by the SDT could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint instead of in preparation for the next contingency.

Response: The SDT believes that System re-dispatch is an acceptable System adjustment to "remain within applicable Facility Ratings" to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the firm transfers cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand.

Voter	Entity	Segment	Vote	Comment
				Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Robert W. Roddy	Dairyland Power Coop.	1	Negative	DPC CONCURS WITH THE MRO COMMENTS.
Jason Shaver	American Transmission Company, LLC	1	Affirmative	For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed if the tripping of the load is either accepted or volunteered by the customer.
Lawrence R. Larson	Otter Tail Power Company	1	Negative	The change precludes the use of direct load control systems that should be allowed to relieve transmission problems. These systems control firm transmission load but rate conditions can allow their use to mitigate transmission problems.

Response: *(Note - MRO did not submit comments with the initial ballot – but did submit the following comment during the formal comment period: For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.)*

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td colspan="5">The SDT has modified the footnote to address your concern.

Footnote ‘b’ now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

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o Interruptible Demand or Demand-Side Management

o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

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<tr><td>Ajay Garg</td><td>Hydro One Networks, Inc.</td><td>1</td><td>Negative</td><td rowspan="2">Hydro One is casting a negative vote for the following reasons:

1. The amendment to the footnote does not add any technical value to the standard. It was added only to satisfy a FERC directive to address comments made to allow non-consequential load loss after a single contingency event, “based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios.”

2. Addressing curtailment of Firm Transmission Service with re-dispatch of resources is a matter of a commercial nature and should be dealt with in the agreements dealing with such services. Issues of contracted transmission services, firm or otherwise, are not a reliability related matter and are not to be dealt with in this standard.</td></tr>
<tr><td>Michael D. Penstone</td><td>Hydro One Networks, Inc.</td><td>3</td><td>Negative</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
				3. Matters of interruption of firm load should be incorporated into this standard only after the FERC NOPR on the definition of the BES is resolved. As it stands, the footnote will pose significant problems if the 100 kV and above FERC proposal is applied across the board, unless the standard specifically states that it applies to the BES as defined by the region (current definition).
Response: 1. & 2. The SDT disagrees. The SDT believes that there could be a direct impact on reliability of the BES associated with uncontrolled interruption of Demand and that it is important to discourage and limit the use of this option.The SDT has added clarity to the footnote. Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected. 3. The SDT disagrees that this needs to wait on the FERC NOPR. This standard is applicable to the BES as it is defined.				
Spencer Tacke	Modesto Irrigation District	4	Negative	I am voting NO vote because of the lack of clarity of the second paragraph of the proposed change. Although paragraph 1 is an improvement to the current wording, and actually allows for some specific flexibility in shedding load for an N-1 event, the lack of clarity in the second paragraph could lead to varied interpretations by members and compliance

Voter	Entity	Segment	Vote	Comment
				auditors. Thank you.

Response: The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

Footnote ‘b’ now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

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- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Dana Cabbell	Southern California Edison Co.	1	Negative	It is SCE’s position that the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local
David Schiada	Southern California Edison Co.	3	Negative	

Voter	Entity	Segment	Vote	Comment
Ahmad Sanati	South California Edison Company	5	Negative	regulator input, for their individual system. When planned load interruption is identified as a response to a single event, the impact to the system is often local in nature. The planned interruption of load may be a desirable alternative to the prohibitive costs associated with a major new transmission project. If the NERC Standards Drafting Team decides to proceed with footnote B, as written, it needs to ensure that Transmission Owners, Transmission Operators, and Transmission Planners have enough time to both design and implement any mitigation plans necessary to be compliant with the new language. In almost all cases the actual implementation of a solution requiring new construction will be dependent on a number of different regulatory agencies providing the necessary permits allowing for its construction. As such, NERC needs to ensure that any time frame associated with compliance to the proposed language be variable, and allow for extended implementation time frames based on system conditions that may delay placing mitigation plans in service. An example of a reasonable variable time frame to be compliant with the proposed language in footnote B would be to start the clock 60 months from receiving the pertinent environmental permitting. In California this could be the issuance of a Draft Environmental Impact Review pursuant to the California Environmental Quality Act.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

The SDT has added more latitude for the Transmission Planner with the modifications and believes that 60 months should be sufficient.

Footnote ‘b’ now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the~~

Voter	Entity	Segment	Vote	Comment
				~~Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Henry Ernst-Jr	Duke Energy Carolina	3	Negative	On the initial ballot of TPL-001-1 Duke Energy also voted "Negative", primarily because Duke believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We also sought rehearing on the Commission's March 18 Order Setting Deadline for Compliance (Docket No. RM06-16), with respect to this and other issues. We believe that FERC's directive in that Order to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the potential impacts (environmental, historical, archaeological, aesthetic...) of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. With this "Negative" vote, Duke

Voter	Entity	Segment	Vote	Comment
				offers the following ideas on alternatives for the SDT to consider that will allow for appropriate discretion and facilitate proper planning while allowing non-consequential load loss (NCLL). The standard should allow for dropping of limited amounts of non-consequential load in situations where it would be reasonable for a bounded time period and under restricted system conditions (e.g. 1-3 years only when load is >90 % of peak conditions). Dropping of non-consequential load would be prudent planning in situations where the near term impact of load projections or implementation of nearby transmission/generation projects will alleviate the necessity of an upgrade to meet N-1 conditions. Also, reliability of service to end-use customer is impacted by the entire system from source to load. Where allowance for NCLL would not greatly impact individual end-use customers' level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to avoid projects without greatly impacting a customer's outage frequency and duration should be acceptable. Use of reliability metrics (e.g. SAIFI/SAIDI/ASAI) should also be considered by the SDT for determination of acceptable use of NCLL.
Luther E. Fair	Gainesville Regional Utilities	1	Affirmative	Even though I am voting in the affirmative, I agree that most of the comments offered by Duke and Norther Indiana in their earlier statements have merit and should be considered. Also, I believe that the use of reliability metrics should be considered by the SDT for determination of acceptable use of NCLL.
Mace Hunter	Lakeland Electric	3	Negative	Reliability should consider the entire system from source to load. Where allowance for NCLL would not greatly impact individual end-use customer's level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to delay projects without greatly impacting a customer's outage frequency and duration should be acceptable. Use of reliability metrics should also be considered by the SDT for determination of acceptable use of NCLL.
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.				

Voter	Entity	Segment	Vote	Comment
				Footnote ‘b’ now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Sammy Roberts	Progress Energy Carolinas	1	Negative	Progress Energy applauds NERC’s efforts to improve the footnote (b) language with respect to conditional allowance of curtailing Firm Transmission Service, which is addressed in the second paragraph of the proposed new footnote (b). PE remains concerned, however, that the first paragraph of the proposed new footnote (b) does not allow for curtailment of non-radial non-consequential load. The ability to curtail non-consequential load in the planning horizon can be a useful tool to mitigate local area issues, and has not been detrimental to
Lee Schuster	Florida Power Corporation	3	Negative	

Voter	Entity	Segment	Vote	Comment
Sam Waters	Progress Energy Carolinas	3	Negative	the Bulk Electric System (BES). Disallowing the curtailment of non-radial non-consequential load essentially prohibits taking action in situations in which the load in question is clearly at a localized self-contained level of the system, i.e. the distribution system(s) served by the Transmission Owner. Prohibiting the curtailment of local load thus constitutes regulating distribution feeder reliability rather than BES reliability. Events that could be mitigated through the curtailment of local, non-radial non-consequential load are infrequent, and such curtailment has no material effect on the reliability of the BES. PE therefore suggests that the following addition (item (3)) to the first paragraph of the proposed footnote (b) be considered: “No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, and/or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities, and/or (3) Planned or controlled interruption of any additional Load required to mitigate the post-contingency results, provided that the non-consequential load being shed for the event is localized, and provided that the total load shed for the event does not exceed 2% of the Planned system peak demand or 200 MW, whichever value is less.”
Wayne Lewis	Progress Energy Carolinas	5	Negative	

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The SDT did not adopt a numerical limit as it believes that any single numerical value applied on a ntion-wide basis was not equitable for all entities.

Footnote ‘b’ now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

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- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial~~

Voter	Entity	Segment	Vote	Comment
				~~Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Timothy VanBlaricom	California ISO	2	Negative	The California ISO supports NERC's request for a public technical conference to be held, as described in NERC's April 19, 2010 request for rehearing and motion for stay of the March 18 Order (RM06-16-009), to provide the opportunity to gain industry input and written comments regarding the Commission's TPL-002-0 directive for NERC to develop a modification to the TPL-002-0 Table 1 footnote b.
Response: The SDT agreed that a technical conference would be of value and held such a conference on August 10, 2010.				
Terry L. Blackwell	Santee Cooper	1	Negative	The Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning processes appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. Table B footnote still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, and local customers should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. The Commission's directive sets forth an expectation that NERC is to implement standards that address all loss of load at costs that may not be commensurate with bulk power system reliability, as statutorily defined, which is fundamentally different from what the Reliability Standards were intended to do.
Zack Dusenbury	Santee Cooper	3	Negative	
Suzanne Ritter	Santee Cooper	6	Negative	

Voter	Entity	Segment	Vote	Comment
Response: The SDT is not in position to comment on FERC's authority. The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.				
Kimberly J. Jones	North Carolina Utilities Commission	9	Negative	The NC Utilities Commission is concerned that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1, and as explained in draft footnote b, is an inappropriate overreach into service issues that are more appropriately addressed by state regulatory commissions. This requirement does not provide any benefit to reliability of the bulk electric system and could undermine state efforts to balance reliability issues with cost of service issues. The standard should continue to allow Transmission Planners to use discretion regarding loss of non-consequential load, understanding that state commissions are positioned to force electric utilities to address local service quality issues on an expedited basis, should it be necessary and in the public interest.
Response: The SDT understands the concern but believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES. The SDT's approach will leverage existing processes to document and vet the situation. Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the				

Voter	Entity	Segment	Vote	Comment
Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.				
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Negative	THE PROPOSED INTERPRETATION WILL UNDERMINE THE INTERNATIONAL STANDARDS SETTING PROCESS AND COULD RESULT IN DIFFERING INTERPRETATIONS OF STANDARDS ON THE NORTH AMERICAN BULK-POWER SYSTEM.
Response: The SDT disagrees and believes that the footnote has been clarified appropriately within the standards development process.				
Daryn Barker	Louisville Gas and Electric Co.	6	Negative	The revised footnote b on Table 1 imposes additional requirements on the responsible entities. The footnote states: Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. However, R1 states: The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned These statements address different and inconsistent scope. If the change in scope was intended then a change should also be made to R1 to reconcile the inconsistency.
Charlie Martin	Louisville Gas and Electric Co.	5	Negative	Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. However, R1 states: The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned These statements address different and inconsistent scope. If the change in scope was intended then a change should also be made to R1 to reconcile the inconsistency.
Response: The SDT agrees that your assessment is for your portion of the interconnected grid. However, when performance in one system is dependent on generation dispatch in another system or vice versa, the SDT believes that one must ensure that the re-dispatch is feasible. The SDT does not believe that this presents a conflict with Requirement R1.				
John Apperson	PacifiCorp	3	Negative	This proposal warrants a "no" vote due to the current uncertainty regarding the outcome of the FERC TPL-002 NOPR issued by FERC on March 18, 2010. The impacts of the proposed changes to footnote B cannot be assessed separately from the alternative interpretation of TPL-002 proposed by FERC. The proper planning of a transmission system requires that all performance requirements are known and understood. If only some of the requirements are known and understood it is impossible to properly plan, study, assess, and operate the

Voter	Entity	Segment	Vote	Comment
				transmission system.
Response: The current TPL-002 is in force and will remain so until the completion of the cited FERC NOPR. This limited scope revision to footnote 'b' is to add clarity to what is in effect.				
Keith V. Carman	Tri-State G & T Association Inc.	1	Negative	Tri-State does believe that the new footnote is an improvement, but thinks there are still some changes necessary. We believe that the word "only" should be removed from the phrase "...where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities" because that discrimination was not required in FERC Order RM-06-16-009. There may be times when facilities near the temporary radial facilities might fall outside the limits set in reliability criteria but the situation is mitigated if the load shedding occurs at the radial facility. The meaning of the second paragraph of the new footnote is unclear. Tri-State recommends changing it to "Curtailment of Firm Transmission Service is not allowed unless it is coupled with curtailment-offsetting resources that are obligated to re-dispatch. Further, the curtailment activities cannot result in the shedding of any Firm load or in violations of Facility Ratings, either internal or external to the planning region." We believe that FERC's directive in FERC Order RM-06-16-009 to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load.
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.				

Voter	Entity	Segment	Vote	Comment
Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected. The SDT is not in position to comment on FERC's authority.				
Claudiu Cadar	GDS Associates, Inc.	1	Negative	We do not agree with the proposed changes due to several reasons. Although the proposed change will directly influence the reliability standards and transmission system performances, will also have an indirect impact on the economic side with respect to the expansion of existing transmission system. We believe that FERC directive as stipulated in Order 693 cannot constrict, nor impose certain actions outside of the reliability limits. We believe that since these events are merely isolated and rarely enforced, the decision of mandating a great financial effort as a consequence of the proposed changes would certainly be counterbalanced by its feasibility when compare with the current cost of load shedding. While the revised footnote b can be certainly considered an improvement from the current version, however it still does not allow the joined entities involved to have power over the decision making when BES reliability is not an issue. We also believe that any mandatory changes implemented in the TPL standards under the

Voter	Entity	Segment	Vote	Comment
				current scenario are not entirely feasible unless all other issues such as the definition of the BES, Consequential / Non-consequential Load, BES Critical Element, etc gets resolve ahead. The revision with respect to load shedding, specifically the portion about shedding loads on newly radial facilities, does not match the version 1 TPL standard definition of consequential load loss. To approve the proposed revision to footnote 'b' would create an unnecessary discrepancy between the version 1 TPL standard under consideration and the existing standards. We recognize that the Version 1 will replace Version 0, but since it appears that the performance standard with respect to footnote 'b' is intended to be same in the revised footnote and the Version 1 standard, it only makes sense that the revised version 0 footnote 'b' match the consequential load loss definition contemplated in Version 1. In the light of the above we suggest the Commission to approach different other solutions and ideas for improving the current reliability of the transmission system without enforcing decisions beyond its statutory scope. We advance an alternative to this matter meant to balance the reliability of the transmission system and its indirect financial impact. Although the solution that we offer would require an extended time for development and implementation, however we urge NERC to consider it in its further approach. Our alternative consists mainly in implementing an additional term such as "Critical Load" which we have briefly figured that would consist in particular load necessary to be maintained in service without interruption. Even though this new term would seemed to be at first related with the quality of the service, however a joint association of transmission planners, customers, regulatory entities as decision makers can simply individualize the load that cannot be shed, as well as future transmission improvements that will be required to serve this envisioned small amount of load rather than the entire load. In this way we will create a reasonable balance in between the reliability of the transmission system and the cost to maintain / improve this reliability.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

The current TPL-002 is in force and will remain so for the forseeable future. This limited scope revision to footnote 'b' is to add clarity to what is in effect.

Project 2006-02 is under revision and the clarifications of footnote 'b' will be considered by the SDT for future revisions of TPL-001-2.

The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

Voter	Entity	Segment	Vote	Comment
Ronald D. Schellberg	Idaho Power Company	1	Negative	While the proposed revisions are an improvement to the prohibition on loss of non-consequential load for a single contingency proposed in the recently failed TPL-001-1 ballot, that the prohibition of loss of non-consequential load for events resulting the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. However, the removal of: "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers." will require significant adjustments in either TRM or TTC reductions to be compliant with this revised standard in the WECC Region. To construct additional transmission facilities to maintain present day business could easily exceed 10 Billion dollars throughout the WECC region. For example, the Pacific AC Intertie currently has a TTC of 4800 MW spread across 3 500 kV transmission lines. With the loss of one Transmission line, the Pacific AC intertie drops to 3200 MW. Removal of this sentence

Voter	Entity	Segment	Vote	Comment
				would require TP either to drop the Firm TTC of the Intertie to 3200, or include a TRM reservation of at least 1600 MW. The TPs would not be able to say that a loss of 1600 MW of import capacity would not result in curtailments of firm load. Just about all multi transmission line paths in the WECC Region would suffer. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. In the case of long interties between subregions of WECC, these interties have never been planned to operate in this manner. Idaho Power recommends that the sentence permiting system adjustments be reinserted into Footnote B.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

The SDT believes that System re-dispatch is an acceptable System adjustment to "remain within applicable Facility Ratings" to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the firm transfers cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the

Voter	Entity	Segment	Vote	Comment
Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.				
Francis J. Halpin	Bonneville Power Administration	5	Affirmative	For consistency, regarding the firm transfer issue, the term "Firm Transmission Service" should be replaced with "Firm Transfers" in order to be consistent with the fourth column of the existing Table 1 "Transmission System Standards - Normal and Emergency Conditions".

Response: The SDT agrees and has made the change.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~

o Interruptible Demand or Demand-Side Management

o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application

Voter	Entity	Segment	Vote	Comment
				is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Kim Warren	Independent Electricity System Operator	2	Affirmative	IESO supports the revisions made to footnote 'b' based on the present definitions of BES and Firm Demand and on the understanding that the NERC standards apply only to the BES as defined in the NERC Glossary as follows: "As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighbouring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition." To be clear, our interpretation of the present definition of BES is that it defers to each Regional Reliability Organization to define the elements of the power system that are considered BES and, therefore in the NPCC Region, "BES as defined by NERC" = "BPS as defined by NPCC".
Response: The SDT agrees that the standard applies to the BES as defined in the Glossary.				
Jacquie Smith	ReliabilityFirst Corporation	10	Affirmative	If this revision is an urgent action, then the implementation timeframe should be shorter. In the clarification paragraph below, I do not understand the first sentence. Are there commas missing? What is the requirement and what is the exception? Also, I question the validity of using "should" in the second sentence. If it is a requirement, then it needs to be stated as a requirement. If it is a suggestion, then it does not belong in the standard. No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.
Response: This was originally classified as an 'urgent action' revision to meet the FERC due date which was June 30, 2010, not because NERC had classified the modification as urgent for reliability. Note that FERC modified the due date to March 31, 2011 - this allows several more months of				

development time and the SAR was revised to indicate that the proposed modification to footnote ‘b’ is no longer an Urgent Action revision.

Commas have been added as appropriate and a re-wording was made which should make this clear.

‘Should’ has been replaced by ‘would’ to provide additional clarity.

Footnote ‘b’ now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
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- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
David H. Boguslawski	Northeast Utilities	1	Affirmative	Northeast Utilities (NU) believes the language of the proposed revision to footnote ‘b’ can be better defined as the proposed revision is subject to interpretation by the different entities and regulatory agencies. Future conflicts can be minimized by further clarifying the proposed revision. Also, NU is concerned that this new modification does not specify the amount of permissible load shed nor does it require the planning entity to minimize load shedding under this exception.

Response: The SDT has made several clarifying changes to the footnote which should alleviate your concerns.

Voter	Entity	Segment	Vote	Comment
. Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.				
Donald S. Watkins	Bonneville Power Administration	1	Affirmative	On the firm transfer issues, the term "Firm Transmission Service" should be replaced with "Firm Transfers" to be consistent with the fourth column of the existing Table 1 Transmission System Standards - Normal and Emergency Conditions.
Rebecca Berdahl	Bonneville Power Administration	3	Affirmative	
Brenda S. Anderson	Bonneville Power Administration	6	Affirmative	
Response: The SDT agrees and has made this change. Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand.				

Voter	Entity	Segment	Vote	Comment
				Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Frank Gaffney	Florida Municipal Power Agency	4	Affirmative	Please see FMPA comments submitted through the concurrent comment period for Project 2010-11
David Schumann	Florida Municipal Power Agency	5	Affirmative	
Response: Please see the response to FMPA comments above.				
Carter B Edge	SERC Reliability Corporation	10	Affirmative	The footnote makes clearer when load can be dropped for planning purposes. By making this footnote more specific, it supports reliability and helps stakeholders apply the TPL standards.
Response: Thank you for your support.				

Voter	Entity	Segment	Vote	Comment
Timothy Beyrle	City of New Smyrna Beach Utilities Commission	4	Affirmative	This is an area of fuzziness between State jurisdiction and Federal jurisdiction. In all honesty, shedding load for local area impacts has nothing to do with BES reliability and should not be under FERC jurisdiction under Section 215 of the Federal Power Act, but rather State jurisdiction for quality of service issues. However, there is also the matter of FERC jurisdiction over commercial matters and the opportunity to "game" the original footnote by transmission providers by allowing firm load shedding to grant firm transmission service for themselves, thereby avoiding or deferring transmission investment, while at the same time denying or requiring others to build the same transmission avoided in order to obtain transmission service. We can see how difficult it is from a drafting team's perspective in achieving a balanced position between these different matters. The drafting team should be applauded for finding a reasonable position.
Response: Thank you for your support.				
Larry E Watt	Lakeland Electric	1	Affirmative	This issue is better handled within the development of the new TPL-001 standard.
Response: The current TPL-002 is in force and will remain so until the completion of the TPL-001-2 effort. This limited scope revision to footnote 'b' is to add clarity to what is in effect.				

Comment Form for SAR and Footnote 'b' in Project 2010-11: TPL Table 1 Order

Please **DO NOT** use this form to submit comments on the 2nd posting for Project 2010-11: TPL Table 1 Order. This comment form must be completed by **October 8, 2010.** This is a 30-day informal comment period. The drafting team will provide a summary response to the one question asked on the comment form, but will not provide an individual response to each comment submitted.

If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Background Information
Second Posting for Project 2010-11: TPL Table 1 Order

The 2nd posting is part of the continuing effort to address FERC Orders which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system.

The 2nd posting is the result of the SDT review of the written comments received from industry on the initial ballot and the inputs received from the Technical Conference of August 10, 2010.

While the initial ballot results came close to the required approval percentage, it was clear to the SDT from the cited inputs that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when load could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote 'b' allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote 'b' were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a

process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential load was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term 'fringes' was seen as problematic and application at the 'fringes' could possibly be discriminatory.
- If interruption of non-consequential load was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote 'b'. This led to the approach shown in the 2nd posting where the SDT has taken the concept of allowing interruption of demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with the ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote 'b' in a way that is an equal and effective method and that likely will be acceptable to all concerned parties.

The 2nd posting provides a revision to TPL Table 1 footnote 'b' to provide clarity to industry with regard to the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. The referenced table appears in TPL-001, TPL-002, TPL-003, and TPL-004 so while the FERC Order was for TPL-002, the change is reflected in all 4 standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The SDT is proposing a revision to footnote 'b' in the TPL tables to comply with FERC Orders which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Do you agree with the proposed changes and if not, please provide specific reasons for your disagreement.

   ☐ Yes
   ☐ No
   Comments:

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. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

Future Development Plan:

Anticipated Actions	Anticipated Date
1. 30-day posting	September 2010
2. 30-day pre-ballot period	November 2010
3. Initial ballot	December 2010
4. Recirculation ballot	January 2011
5. Submit to BOT for approval	January 2011
6. File with FERC	February 2011

A. Introduction

1. Title: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. Number: TPL-004-1

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-1_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-1_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Revised footnote 'b' pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	 Yes Yes Yes Yes	 Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	 No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- Demand that is directly served by the elements that are removed from service as a result of the Contingency, or
- Interruptible Demand or Demand-Side Management
- Demand that does not adversely impact overall BES reliability where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

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. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

Future Development Plan:

Anticipated Actions	Anticipated Date
1. 30-day posting	September 2010
2. 30-day pre-ballot period	November 2010
3. Initial ballot	December 2010
4. Recirculation ballot	January 2011
5. Submit to BOT for approval	January 2011
6. File with FERC	February 2011

A. Introduction

1. Title: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. Number: TPL-004-1

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-1_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-1_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) ~~No interruption of firm Load is allowed except~~An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency, or
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.~~ ~~Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch do~~es~~es not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

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. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

Future Development Plan:

Anticipated Actions	Anticipated Date
1. 30-day posting	September 2010
2. 30-day pre-ballot period	November 2010
3. Initial ballot	December 2010
4. Recirculation ballot	January 2011
5. Submit to BOT for approval	January 2011
6. File with FERC	February 2011

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**
2. **Number:** TPL-003-1a
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
4. **Applicability:**
   - **4.1.** Planning Authority
   - **4.2.** Transmission Planner
5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-1_R1 and TPL-003-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item "e" on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
1a	TBD	Revised footnote 'b' pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

<table>
<tr>
<td>D [d]

Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</td>
<td>3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure):

1. Generator
2. Transmission Circuit
3. Transformer
4. Bus Section
<hr>3Ø Fault, with Normal Clearing[e]:

5. Breaker (failure or internal Fault)
<hr>6. Loss of towerline with three or more circuits
7. All transmission lines on a common right-of way
8. Loss of a substation (one voltage level plus transformers)
9. Loss of a switching station (one voltage level plus transformers)
10. Loss of all generating units at a station
11. Loss of a large Load or major Load center
12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required
13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate
14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</td>
<td>Evaluate for risks and consequences.

▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.
▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.
▪ Evaluation of these events may require joint studies with neighboring systems.</td>
</tr>
</table>

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- Demand that is directly served by the elements that are removed from service as a result of the Contingency
- Interruptible Demand or Demand-Side Management
- Demand that does not adversely impact overall BES reliability where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

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. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

Future Development Plan:

Anticipated Actions	Anticipated Date
1. 30-day posting	September 2010
2. 30-day pre-ballot period	November 2010
3. Initial ballot	December 2010
4. Recirculation ballot	January 2011
5. Submit to BOT for approval	January 2011
6. File with FERC	February 2011

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-1a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-1_R1 and TPL-003-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
1a	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) ~~No interruption of firm Load is allowed except~~An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~ Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.~~ ~~Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2
Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

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. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

Future Development Plan:

Anticipated Actions	Anticipated Date
1. 30-day posting	September 2010
2. 30-day pre-ballot period	November 2010
3. Initial ballot	December 2010
4. Recirculation ballot	January 2011
5. Submit to BOT for approval	January 2011
6. File with FERC	February 2011

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-1b

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-1_R1 and TPL-002-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	April 2010	Revised footnote 'b' pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- Demand that is directly served by the elements that are removed from service as a result of the Contingency
- Interruptible Demand or Demand-Side Management
- Demand that does not adversely impact overall BES reliability where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

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. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

Future Development Plan:

Anticipated Actions	Anticipated Date
1. 30-day posting	September 2010
2. 30-day pre-ballot period	November 2010
3. Initial ballot	December 2010
4. Recirculation ballot	January 2011
5. Submit to BOT for approval	January 2011
6. File with FERC	February 2011

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-1b

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-1_R1 and TPL-002-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	April 2010	Revised footnote 'b' pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:~~:~~

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by “study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies).” 2. “…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).” 3. “Include the effects of existing and planned protection systems, including any backup or redundant systems.” *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as “A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.”
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

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. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

Future Development Plan:

Anticipated Actions	Anticipated Date
1. 30-day posting	September 2010
2. 30-day pre-ballot period	November 2010
3. Initial ballot	December 2010
4. Recirculation ballot	January 2011
5. Submit to BOT for approval	January 2011
6. File with FERC	February 2011

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)

2. **Number:** TPL-001-1

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-1_R1 and TPL-001-1_ R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
Compliance Monitor: Regional Reliability Organization.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame
Annually

1.3. Data Retention
None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	 Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	 Yes Yes Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	 No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

  - Demand that is directly served by the elements that are removed from service as a result of the Contingency
  - Interruptible Demand or Demand-Side Management
  - Demand that does not adversely impact overall BES reliability where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

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This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

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Proposed Action Plan and Description of Current Draft:

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Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote 'b' allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote 'b' were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term 'fringes' was seen as problematic and application at the 'fringes' could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote 'b'. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote 'b' in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

Future Development Plan:

Anticipated Actions	Anticipated Date
1. 30-day posting	September 2010
2. 30-day pre-ballot period	November 2010
3. Initial ballot	December 2010
4. Recirculation ballot	January 2011
5. Submit to BOT for approval	January 2011
6. File with FERC	February 2011

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)

2. **Number:** TPL-001-1

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

    4.1. Planning Authority

    4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-1_R1 and TPL-001-1_ R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	 Yes Yes Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	 No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) ~~No interruption of firm Load is allowed except~~An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities. Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Implementation Plan for Project 2010-11: TPL Table 1 Order

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

Revision to Sections of Approved Standards and Definitions

There are no new definitions in the proposed standards.

Compliance with Standards

Standards	**Functions That Must Comply With the Associated Requirements**	
TPL-001-0.2: System Performance Under Normal (No Contingency) Conditions (Category A) TPL-002-0c: System Performance Following Loss of a Single Bulk Electric System Element (Category B) TPL-003-0b: System Performance Following Loss of Two or More Bulk Electric System Elements (Category C) TPL-004-0a: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)	Transmission Planner	Planning Authority
	X	X

Effective Dates

The effective date is the date entities are expected to meet the performance identified in this standard.

The effective date for footnote 'b' will be the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption.

All other requirements remain in effect as per previous approvals.

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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Informal Comment Period Open
September 8 - October 8, 2010

Now available at: http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Project 2010-11 TPL Table 1 Order (Footnote 'b')
The TPL Table 1 Order Drafting Team is seeking comments on Table 1 footnote 'b' in TPL-001-1 through TPL-004-1 **until 8 p.m. EDT on October 8, 2010**:

FERC Order RM06-16-009 requires the ERO to clarify TPL-002-0, Table 1 - footnote 'b,' regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system and originally directed NERC to file the revised standards by June 30, 2010. To meet this directive a proposed revision was posted for "Urgent Action" and balloted from May 17-27, 2010. The proposed revision achieved a quorum (84%) and almost enough affirmative votes (64%) to achieve weighted segment approval; however many balloters provided comments indicating the need for additional modifications. Following the initial ballot, FERC extended the due date to March 31, 2011; thus the project is no longer considered "Urgent Action."

The drafting team developed a second draft of the proposed revision to TPL Table 1 footnote 'b' that reflects consideration of the comments received from industry on the initial ballot and the inputs received from the Technical Conference held on August 10, 2010. The second draft allows interruption of demand without numerical constraints where the application is subject to review and acceptance in an open and transparent stakeholder process.

Because Table 1 appears in TPL-001, TPL-002, TPL-003, and TPL-004, the change is reflected in all four standards:

TPL-001-1 - System Performance Under Normal (No Contingency) Conditions (Category A)

TPL-002-1b - System Performance Following Loss of a Single Bulk Electric System Element (Category B)

TPL-003-1a - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)

TPL-004-1 - System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

Transition from Reliability Standards Development Procedure Version 7 – to Standard Processes Manual
In accordance with the Standard Processes Manual approved by FERC on September 3, 2010, the drafting team is using an "informal" comment period to solicit stakeholder feedback. The new standard development process allows drafting teams to use informal comment periods. Unlike formal comment periods where a drafting team

provides a response to each comment submitted, with informal comment periods the drafting team provides a summary response to each question asked on its comment form. The summary response will indicate whether stakeholders support the proposal and will identify any additional changes made based on stakeholder comments. With informal comment periods drafting teams are not required to provide an individual response to each comment submitted – this change to the process is intended to give drafting teams more time to deliberate on technical issues, as opposed to deliberating on individual responses to comments. Note that while informal comment periods are allowed in the new standard process for preliminary drafts of proposed standards, formal comment periods are still required for the final draft of each standard.

Instructions

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page:
http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Next Steps

The drafting team will draft and post a summary response to the comments received and, if applicable, a revised 'footnote b.' After reviewing the comments, and determining whether there is a need for additional feedback on the proposed footnote b language, the drafting team will determine its next steps. The next steps may include a 30-day formal comment period or may include a 45-day formal comment period with a ballot pool formed during the first 30 days of that comment period and an initial ballot conducted during the last 10 days of the 45-day comment period.

Project Background

The Assess Transmission Future Needs Standard Drafting Team (Project 2006-02) has developed a clarification to TPL Table 1 — footnote 'b' concerning the loss of load and handling of firm transfers when a single contingency occurs on the transmission system. Since this clarification may present a different interpretation of footnote 'b' than the one presently used by some entities, the SDT is proposing a 60 month implementation plan to allow those entities time to react.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Program Administrator, at monica.benson@nerc.net or at 609.452.8060.

Individual or group. (43 Responses)
Name (32 Responses)
Organization (32 Responses)
Group Name (11 Responses)
Lead Contact (11 Responses)
Question 1 (43 Responses)
Question 1 Comments (43 Responses)

-
Group
Arizona Public Service Company
Jana Van Ness
Yes
Individual
Don Gilbert
JEA
No
The requirement in general is acceptable; however, there needs to be an added "such as" clause to the referenced "...in an open and transparent stakeholder processes." I suggest adding "..."...in an open and transparent stakeholder processes such as the FERC approved regional 890 process that includes the load serving entity affected".
Group
Northeast Power Coordinating Council
Guy Zito
No
1. The introductory paragraph discourages the Interruption of any Demand, implying that no Demand directly connected should be interrupted. However, it is an acceptable practice to allow for some Interruption of Demand that is directly connected to the element that is removed from service. Recommend that the drafting team revise the wording to eliminate this implication, and soften the expectation such that it is recognized that some Interruption of Demand is unavoidable by system configuration, but that each entity should establish a reasonable limit on how much demand can be interrupted due to the loss of an element. 2. The Statement that “However, Demand may need to be interrupted in limited circumstances to address BES performance requirements” in the introductory paragraph contradicts bullet 3 “Demand that does not adversely affect BES …” 3. The third Bullet is confusing. Suggest revising the wording to clarify the adverse impact to the BES system, documentation expectations, and to answer fundamental questions such as who has the authority to decide the use if the stakeholder process is “accepting”, and the necessity of having a stakeholder process. It is unlikely that the interruption of Demand will adversely impact the BES system. This constraint is too broad. The language in this bullet also allows that non-consequential Demand interruption could be used to mitigate reliability violations arising from the NERC Category B contingency events (i.e., single element contingencies). 4. In the second paragraph, the conditions when interruption of Firm Transfers may be used are not specified. 5. In the last sentence of the second paragraph, “would” should be replaced by “must”. Alternatively, possible rewording of footnote “b” to be considered: b) An objective of the planning process should be to minimize the likelihood of interrupting Demand and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements or other local reasons which have no adverse impact on overall BES reliability or the interconnected BES. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Demand that does not adversely impact overall reliability of the BES or the interconnected BES and where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of available resources, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected. The Drafting Team should reconsider the use of “Load” as opposed to “Demand”. By definition (NERC Glossary dated April 20, 2010) Demand is: “1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.” Load is defined as: “An end-use device or customer that receives power from the electric system.” This terminology is more appropriate to the application used in the Table.
Group

SERC Planning Standards Subcommittee
Philip R. Kleckley
No
The revised text relating to the planning process exceeds what is appropriate for a reliability standard. Existing open and transparent stakeholder processes focus on larger system issues and not on local load serving. We suggest the following: Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Interruptible Demand or Demand-Side Management o Demand that does not adversely impact overall BES reliability and is made temporarily radial as a result of the Contingency, where that Demand must be interrupted to meet performance requirements. Curtailment of firm transfers is allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected. "The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers."
Individual
RoLynda Shumpert
South Carolina Electric and Gas
No
SCE&G believes the first sentence "An object of the planning process is to avoid interruption of Demand." goes beyond what is appropriate for a reliability standard and therefore should be deleted. Also, the part of the sentence that states "and where the application is subject to review and acceptance in an open and transparent stakeholder process" goes beyond what is appropriate for a reliability standard and should be deleted.
Individual
Laura Zotter
ERCOT ISO
Yes
Group
PacifiCorp
Sandra Shaffer
No
PacifiCorp believes that the current version of footnote "b" is an improvement over the language that currently exists in the standard, except for one component of the revised footnote. The third bullet in the draft standard currently limits the interruption of Demand if it does not adversely impact overall BES reliability, where the circumstances describing the use of the interruption are documented (including alternatives evaluated) and the application is subject to review and acceptance in "an open and transparent stakeholder process." PacifiCorp believes that the language requiring review and acceptance of an application of demand interruption through any sort of stakeholder process should be removed. It is not practical or effective to prescribe that either this standard or any other standard requires stakeholder approval in order to maintain compliance. As presently drafted, this requirement for stakeholder review and acceptance appears to be inconclusive and indeterminate as to what is required for registered entities to comply. Instead, this third bullet should require the documentation, by the Planning Authority and Transmission Planner, of the circumstances describing the use of Demand interruption – including methodologies used, assumptions relied upon, and alternatives evaluated – as part of the Planning Authorities' and/or Transmission Planners' documentation of results in their annual Reliability Assessments. These annual assessments are already submitted to the appropriate Regional Reliability Organization pursuant to TPL-002-1b Requirement R3. This annual assessment can be provided by the ERO to other appropriate third parties upon their request.
Individual
Greg Rowland
Duke Energy
Yes
Duke Energy strongly supports this revised footnote 'b'. We believe that it provides for appropriate consideration of stakeholder input in decision-making for local reliability issues, while maintaining the reliability of the Bulk Electric System.
Individual
Steve Stafford
Georgia Transmission Corporation
Yes

Group
PPL Corp
John Cummings
Yes
PPL believes that Footnote b as described in TPL-002-1b, Draft 2, August 30, 2010 is fine provided an accompanying Requirement (with appropriate VRF and VSL) and Measure is added to the TPL standard(s) to require and document notification of the affected Demand parties and the involvement of the affected Demand parties in an open process as described by Footnote b, third bullet.
Individual
John Canavan
NorthWestern Energy
No
In addition to the three bullet items, add a fourth bullet item to the list of limitations under the body of footnote b: “In no case will a total loss of load that is less than 50 MW be considered a violation of this standard.”
Individual
Tim Ponseti
TVA Transmission Planning & Compliance
No
TVA supports FERC's actions on improving reliability of the BES; however, TVA believes that the new proposal is focusing more on reliability of local loads than on the overall reliability of the BES. Footnote b should focus only on the overall reliability of the BES. Reliability of local loads should be addressed outside the TPL standards and therefore should not be used/referenced in footnote b. Also existing stakeholder processes (referred to in the SDT proposal) typically focus on larger system issues and not on local load serving. Thus TVA believes that some local load should be allowed to be dropped in order to maintain BES reliability. However TVA does believe that there should be a limit of how much load can be dropped in order to maintain BES reliability. TVA believes that 50 MW is a reasonable number for this limit. Based on the above, TVA proposes substituting the following for the revised footnote b: Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: Demand that is directly served by the elements that are removed from service as a result of the Contingency Interruptible Demand or Demand-Side Management Demand that does not adversely impact overall BES reliability, where that Demand (not to exceed 50 MW) must be interrupted to meet performance requirements. Curtailment of firm transfers is allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected.
Individual
Gordon Rawlings
BC Hydro
No
The SDT is to be commended for their efforts to develop clear, unambiguous language for Footnote “b”. From the discussions that have taken place it seems that there are many different perspectives and to get agreement on specific language will be very difficult. We believe that it would be useful to identify the main issues that Footnote “b” needs to address and we consider those main issues to be: • Definitions of (a) Consequential Load Loss, (b) Firm Demand, (c) Firm Transmission Capability (as distinct from the OATT term, “Firm Transmission Service”), (d) Firm Transfer (this could be defined as transfers using the OATT’s Firm Transmission Service, (e) Manual System Adjustments (capitalized in the Category C section of TPL-001, but not defined in the NERC Glossary) and (f) the Bulk Electric System (BES). • Identifying permissible Demand/Transfer curtailment actions for (a) the planning studies simulating the Category B event itself and (b) the planning studies associated with determining acceptable actions for preparing for the next set of contingencies should the initial single contingency be prolonged (ie, last several weeks). This would define the acceptable (pre-emptive) “Manual System Adjustments” of Category C events. • Define separate acceptable curtailment actions for (a) curtailment of Demand (ie, end-user load) and (b) curtailment of market to market transfers, that very rarely, if ever, result in the loss of any end-user load. • Define the planning studies required to determine the acceptability of the impacts on the BES resulting from curtailments in a “remote” part of the system that have been accepted by those directly affected by those curtailments. At this point we don’t have specific language to suggest, but we do have the following comments that we hope will help: A. Interruption of Demand: A.1. Consider improving the definition of “Firm Demand” in the NERC Glossary that now reads, “That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions”. Perhaps it could be changed to something like, “That portion of the Demand that the planned transmission system must be able to supply without interruption for Category B events. A.2. Consider stating in Footnote “b” that curtailment of Firm Demand is (a)

not permitted in the simulation of the N-1 event itself and (b) it is not permitted as part of the (pre-emptive) “Manual System Adjustments” needed to prepare for the next set of contingencies should the initial single contingency be prolonged (ie, last several weeks). B. Interruption of Firm Transfers: B.1. “Firm Transfers” could be defined as transfers using the OATT’s Firm Transmission Service, but consider developing a system reliability-based term for “Firm Transmission Capability” instead of referring to the tariff-based NERC definition of “Firm Transmission Service”. This would recognize the difference between planning standards and commercial/tariff rules. The NERC definition of “Firm Transmission Service” is now, “The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption”. Transmission tariffs address the priority of curtailments when the loading on a transmission path needs to be reduced for whatever reason (single- or multiple-contingencies). The NERC transmission planning standards need a system reliability definition like, “Firm Transmission Capability” is the transmission capability across a cut-plane, on a defined transmission path or across a defined flowgate that is available, before any manual corrective actions are taken, following the worst Category B event under the most onerous normal system conditions considering all plausible generation dispatch patterns and the full range of expected load levels.” B.2. Consider stating in Footnote “b” that curtailment of Firm Transfers is only permitted to the extent that redispatch of generation can be implemented so that delivery to the Firm Transfer recipient is not interrupted (a) in the planning studies of the Category B event itself and (b) as part of the (pre-emptive) “Manual System Adjustments” needed to prepare for the next set of contingencies should the initial single contingency be prolonged (ie, last several weeks). C. General Comments: C.1. Consider replacing the first bullet of the proposed Footnote “b” with simply “Consequential Load Loss” since the NERC Project 2006 02 (TPL 001) Standard Drafting Team is introducing the following definition: Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault C.2. Consider removing “Demand-Side Management” (DSM) from the second bullet because that term is too general. The present definition of DSM in the NERC Glossary is: “The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use”. C.3. Consider being more specific on what constitutes acceptable “Interruptible Demand”, like: “Interruptible Demand that is part of an automatic real-time Direct Control Load Management (DCLM) system that is activated by the contingencies that require it and that is a completely “dual-redundant” scheme including all communications equipment. The DCLM system must result in automatic curtailment of Demand that is fast enough to maintain all BES system performance standards (eg, voltage stability, voltage dip, etc)”. C.4. Consider eliminating the description of how interrupting Demand that does not adversely impact overall BES reliability was accepted (ie, the stakeholder process, etc). If such a process were undertaken and it resulted in acceptance that the Demand could be curtailed for Category B events, wouldn’t that simply mean that the Demand was “Interruptible Demand”. It really doesn’t matter what process resulted in it being accepted. The key considerations are that (a) if the interruption of that Demand is necessary to maintain BES reliability, then it must be interrupted in a very reliable manner (ie, dual redundant scheme, etc) and (b) if the interruption of that Demand is not necessary to maintain the reliable performance of the BES, then that should be confirmed by the planning studies (ie, it doesn’t need to have an expensive, sophisticated, dual-redundant DCLM scheme since the impact on the BES is acceptable even if the scheme doesn’t work). D. Additional Questions related to Curtailment of Firm Transfers: In the past, the latter part of Footnote B read: “To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.” The last part of the proposed Footnote B now reads: “Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected.” We would like to understand the implications of the proposed Footnote B as it relates to curtailment of Firm Transfers (as per definition proposed earlier) for the following questions: 1) In the most recent draft of Footnote B, why was the NERC defined term ‘Firm Transmission Service’ replaced with the non-defined term ‘firm transfers’? 2) In the most recent draft of Footnote B, why was the tone softened from “No curtailment of Firm Transmission Service is allowed, except…” to “Curtailment of firm transfers is allowed when…”? 3) Assuming an outage of a single transmission line (N-1 Category B event) has occurred and assuming that no “resources [are] obligated to redispatch” for this outage, would a transmission provider be allowed to curtail Firm Transmission Service (NERC defined term) that it has sold in order to prepare to withstand the next worst credible contingency? 4) Would transmission providers be allowed to sell Firm Transmission Service on a path above what could be delivered with any one element of that path out of service and a range of operating conditions? 5) If the proposed Footnote B is approved, would utilities have to reinforce their system (within 60 months) to ensure that Firm Transmission Service for particular paths would not be curtailed can be delivered when any one element of that path is out of service? 6) If a transmission provider employs Generation Dropping for single contingencies in order to support Firm Transmission Service between regions, and assuming there are no provisions for obligated re-dispatch, would the proposed Footnote B force a recalculation of firm vs non-firm transfer capability? 7) Path 66 (PACI) and Path 65 (PDCI) can both see significant derates in their firm transfer capability for single contingencies. How would the proposed Footnote B impact Firm Transmission on these paths?
Group
MRO's NERC Standards Review Subcommittee
Carol Gerou
No

The revised draft is a significant improvement over the first draft. However, we suggest the following minor changes: 1. The criterion of “adversely affect overall BES reliability” is undefined and maybe subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest adding the words “as defined by each Transmission Planner or Planning Authority”. 2. The term of “firm transfers” is undefined and maybe subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest establishing a definition for the term, reverting to the “Firm Transmission Service” term, or using another appropriate defined term.
Individual
Jon Kapitz
Xcel Energy
Yes
Xcel Energy supports the new interpretation that would allow curtailment of firm transfers or demand for limited conditions where the integrity of bulk electric system is not compromised. However Xcel Energy seeks some clarification regarding the following: The 3rd bullet point in footnote b will need to clarify whether the demand interruption can be done after the contingency, or before the contingency. If it is allowed after the contingency, then the standard would allow violation of voltage or thermal loading criteria for a brief period, after contingency and, before demand curtailment happens. Is this acceptable based on the new interpretation? Since TPL-002 standard deals with NERC Category B contingencies, and footnote b states that curtailment of firm transfers is allowed, it should be clarified if this curtailment is allowed before or after the contingency. If the curtailment is allowed only after the contingency, then the system would be in violation of the thermal or voltage criteria for a brief period till the generation is re-dispatched. Is this allowed by the new interpretation? If curtailment is only allowed in preparation of the contingency, then the firm transfers would be curtailed during system intact conditions, in preparation for the first contingency, resulting in violation of TPL-001 standard. Is this allowed by the new interpretation?
Individual
John Sullivan
Ameren
No
The revised text to footnote b relating to the planning process exceeds what is appropriate for a reliability standard. Existing open and transparent stakeholder processes focus on larger system issues rather than on local load serving issues. We suggest the following text for footnote b: Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Interruptible Demand or Demand-Side Management o Demand that does not adversely impact overall BES reliability and is made temporarily radial as a result of the Contingency, where that Demand must be interrupted to meet performance requirements. Curtailment of firm transfers is allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected.
Individual
Darcy O'Connell
California ISO
Yes
1) Regarding the 2nd bullet provision, we suggest: Interruptible Demand or Demand-Side Management that has been reviewed and approved by the Planning Authority. 2) Regarding the 3rd bullet provision, we suggest: Demand interruption that does not adversely impact overall BES reliability…. 3) Also regarding the 3rd bullet provision, we suggest replacing acceptance with clarification to read “where the application is subject to review and clarification in an open and transparent stakeholder process."
Individual
Doug Hohlbaugh
FirstEnergy
No
FirstEnergy appreciates the efforts of the Assess Transmission Future Needs SDT in reaching a reasonable proposal for clarifying Table 1 footnote B presented in the TPL-001 through TPL-004 standards. We also commend NERC staff for convening an industry technical conference to discuss the topic and FERC staff for their participation in the technical conference as the industry carefully considered various perspectives. The proposed footnote B is much improved from the prior draft proposals. One change that FirstEnergy proposes is to strike the text following the semicolon in the third bullet item which states “and where the application is subject to review and acceptance in an open and transparent stakeholder process.” This text may be intended as explanatory but has the appearance of mandating an approval process that will be auditable through the TPL reliability standards. The statement is not

needed within the framework of mandatory reliability requirements as FERC Order 890 already mandates an open and transparent process related to the planning of the bulk electric system. FERC via the 890 Final Rule modified the pro forma Open-Access Transmission Tariff to require open and transparent stakeholder process to better ensure no undue discrimination and access to the transmission system. The Final Rule beginning at paragraph 418 discusses reform to the Coordinated, Open and Transparent Planning of the transmission system. The Commission direction included eight planning principles required to be within the open process – one of which is dispute resolution. It should be well understood that the transmission planner and planning coordinator share and disseminate all of their planning study results and proposed corrective actions – including the proposed use of Demand interruption – as part of their adherence to Order 890. We appreciate the SDT's careful consideration of our comments.
Individual
Orlando A Ciniglio
Idaho Power
Yes
footnote 'b' is silent with respect to planned removal from service of certain generators. I believe there are many conditions out there where a single contingency can initiate a planned (RAS-initiated) removal of generation. The fact that this is mentioned in footnote 'c', under multiple contingencies, begs the need for futher elaboration/discussion of this option under single contingencies in footnote 'b'.
Individual
Michael Lombardi
Northeast Utilities
No
NU agrees with the language of the proposed revision to Footnote b EXCEPT FOR bullet #3 which suggests that non-consequential demand interruption could be used to mitigate reliability violations arising from the NERC Category B contingency events (i.e., single element contingencies).
Individual
Thad Ness
American Electric Power
Yes
Individual
JC Culberson
ERCOT
No
The introductory paragraph of footnote b includes policy language. Since this is a reliability standard—and not a policy directive—the general narrative setting forth the desired policy goal of minimizing load-shedding is misplaced. Including policy language can cloud the specific issues the standard attempts to address, and ERCOT recommends deleting the first two sentences in the introductory paragraph. The next sentence in the introductory paragraph goes on to state, generally, that demand may be interrupted to "address BES performance requirements." This phrase is vague. To which performance requirements does this refer? The intent is not clear. If the intent is to generally recognize the need to shed load to respect NERC standards and to allow flexibility for an entity to exercise discretion relative to meeting BES performance requirements, then that intent should be clearly reflected in the language. Furthermore, the last sentence of the introductory paragraph and the subsequent bullet points are arguably inconsistent with this approach, because they could be viewed as removing an entity's flexibility/discretion by limiting the circumstances when load can be shed. The second bullet point is unnecessary, because it is already apparent that interruptible demand/demand side management programs can be used according to their terms. This could create confusion in that it could be implied that, absent the need to use these to meet BES performance requirements, using them otherwise is inconsistent with/not allowed under footnote b. Simply put, those products are not load shedding as contemplated by this footnote. Therefore they should not be listed here. With respect to the third bullet point, the phrase "demand that does not adversely impact overall BES reliability" is not adequately defined, and provides opportunity for confusion. This is an ambiguous phrase and can't be linked back to objective NERC standards/requirements. The bullet points should avoid ambiguity to mitigate ambiguity risk in audits. In addition, the last part of the language in this bullet imposing an open and transparent stakeholder process is unclear. What is the intent behind requiring review in a stakeholder process? If it is to establish the ability of the entity to develop load shedding procedures beyond those explicitly contemplated in footnote b, ERCOT questions if it is reasonable for the responsible entity to be required to get "permission" from stakeholders to implement reliability measures related to its obligation as the functional entity. Again, the language simply is not clear. Accordingly, ERCOT recommends this bullet point be removed. If it is retained, it should be revised consistent with these comments to remove ambiguous language to mitigate potential confusion around the meaning/scope of the footnote in the administration of the CMEP. In addition, ERCOT recommends revising the draft footnote b to allow for planned Demand interruption as a means of mitigation during interim periods when a unanticipated (such as unexpected demand growth or unit retirements) or temporary change on the system occurs in a

timeframe that is shorter than the time necessary to plan and implement the system upgrades necessary to avoid the Demand interruption. Finally, in the last paragraph of footnote b, it isn't clear why "Transmission Service" was changed to "transfers." Firm transmission service is a service provided in some regions, and it provides relative value to other types of services—e.g., non-firm and network. The mention of transmission service may also be irrelevant in this footnote, since the allowance of its interruption doesn't also allow for load shedding. Therefore, ERCOT recommends eliminating the last paragraph of footnote b.
Group
Bonneville Power Administration
Denise Koehn
Yes
Individual
Kasia Mihalchuk
Manitoba Hydro
Yes
The changes to Table 1 Note b proposed by the SDT for this second posting are a reasonable approach to the issue of interrupting of "Firm Demand". The requirement to evaluate alternatives to dropping of Firm Demand in a transparent stakeholder process should provide the verification of cost over benefit on a case by case basis. I propose the following editorial changes: 1. The change of "Firm Transmission Services" made in Table 1 should be also be made in each TPL standard as R1 refers to "projected Firm (non-recallable reserved) Transmission Services. 2. Since "Firm Demand" is a defined term, ensure it is capitalized throughout the standard. There is one instance where it is not.
Individual
Charles Lawrence
American Transmission Company
No
The revised draft is a significant improvement over the first draft. However, we suggest the following minor changes: 1. The criterion of "adversely affect overall BES reliability" is undefined and may subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest adding the words "as defined by each Transmission Planner or Planning Authority". 2. The term of "firm transfers" is undefined and may subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest establishing a definition for the term of "firm transfers", reverting to the "Firm Transmission Service" term, or using another appropriate NERC defined term.
Individual
Kathleen Goodman
ISO New England Inc.
No
ISO New England does not allow non-consequential load loss for first contingencies in Planning Analysis, and as an overall matter, ISO-NE believes that the appropriate step is for NERC to modify the footnote in line with the original FERC Order. However, ISO-NE offers the following recommendation to improve the proposed language for footnote b if it is to be retained similar to what has been proposed. In short, ISO-NE proposes changing the third sub-bullet, because the provision is both unnecessary and inappropriate for a NERC Standard. First, the sub-bullet is redundant, because the Commission has ordered that companies add to their Open Access Transmission Tariffs an open and transparent planning process. If Transmission Planners establish their system planning assessments through those processes, then there should be no question that the Planner's assessments have been effectively communicated to the region. Second, the passive nature of the language (i.e., "where the application is subject to review and acceptance…") is unclear as it suggests that someone other than the Planning Coordinator/Transmission Planner is responsible for determining what belongs in a long-term system assessment. Including Demand-Side Management in the standard also appears redundant as Demand Response is used as an asset in the same manner as generation resources. b) When interruption of Demand is utilized within the planning process, such interruption is limited to: 1) Demand that is directly served by the elements that are removed from service as a result of the Contingency. 2) Interruptible Demand or Demand-Side Management 3) Instances where the planned or controlled interruption of Demand results in System performance which meets the requirements of Table 1 for Category B contingencies. When such Demand interruption is utilized in an assessment, the use of such actions must be limited to small portions of the system, be operationally achievable, be of limited duration, and be documented therein.
Individual
Dan Rochester
Independent Electricity System Operator
Yes

Individual
Ed Davis
Entergy Services
No
Entergy disagrees with the proposed language in the third bullet for two reasons. 1. While Entergy supports the idea of “an open and transparent stakeholder process” regarding the use of non-consequential load loss. It is unclear how such a process could be fairly implemented as competing stakeholder interests could prevent resolution. Stakeholders should be defined as those stakeholders whose load could be shed per footnote b, not any and all stakeholders. 2. The “is subject to review and acceptance” implies that some formal voting process would be required by stakeholders. Is this the SDT’s intent? If so would such a process be developed as part of the standard or would it be left up to TO’s? If non-consequential load loss was deemed an acceptable solution across a SEAM, would the TO’s jointly serving the load need to agree?
Group
Dominion
Louis Slade, Jr.
Yes
Individual
Terry Harbour
MidAmerican Energy
No
While the TPL note “b” approach has improved, MidAmerican has concerns that including the wording “review and acceptance” goes beyond the FERC Order 890 order, process, and intent of including the open review process. Therefore, to align with FERC Order 890, the “review and acceptance” should be replaced with “subject to comment”. Anything more exceeds FERC Order 890 and the reason why the review process was included. In the end, Transmission Owning and Operating entities must have final say in the operation of the grid. Entities can comment, but cannot obstruct Transmission Owning and Operating entities from properly operating the grid or reliability could be reduced.
Group
Southern Company
Andy Tillery
No
The revised text relating to the planning process exceeds what is appropriate for a reliability standard. Existing open and transparent stakeholder processes focus on larger system issues and not on local load serving. We suggest that the drafting team go back to the concept of local load being the load that is made temporarily radial by the contingency. That was a much better approach.
Individual
Patrick Farrell
Southern California Edison Company
Yes
SCE appreciates the efforts of the NERC Standards Drafting Team and believes that the team has admirably worked to meet FERC's expectations. SCE would suggest that Footnote "b" be revised to include a semi-colon(;) after the first sub-paragraph and a semi-colon(;) followed by an "and" after the second sub-paragraph, to convey that the three sub-paragraphs are alternative, rather than additive methods for satisfying the requirements for "interruptions."
Individual
Jonathan Appelbaum
United Illuminating Co
No
United Illuminating believes that for TPL Category B contingencies no planned or controlled (non-consequential) interruption of firm demand should occur as a general philosophy for planning the Bulk Electric System (BES). Recognizing there are certain areas of the BES that have unique circumstances that may warrant an exception to this, UI suggests the addition of language that recognizes the limited application of non-consequential load interruption with a process that requires a case-by-case acceptance of such application by the Regional Entity or NERC.
Individual
Michael Moltane
ITC
Yes

The proposed language for the new TPL-001-1 Table 1 footnote b is acceptable to ITC.
Individual
Gregory Campoli
New York Independent System Operator
Yes
The NYISO agrees in principle with the proposed changes, but recommends the following modifications: 1. The introductory paragraph discourages the Interruption of any Demand, implying that no Demand directly connected should be interrupted. However, it is an acceptable practice to allow for some Interruption of Demand that is directly connected to the element that is removed from service. The introductory paragraph is immaterial to the requirement, and therefore unnecessary with the exception of the last sentence which starts the bulleted list. 2. Interruptible demand is an operation tool and not a transmission planning tool, while Demand-Side Management is typically embedded in the load forecast used in the planning process. The second bullet therefore may not be necessary or applicable here, though it is helpful in making clear those are acceptable forms of interruption. 3. The third bullet is confusing. Suggest revising the wording to clarify the adverse impact to the BES system and documentation expectations. Recommend removing reference to the application being subject to review and acceptance in an open and transparent stakeholder process; this is inherent to all documentation and does not need to be emphasized in a footnote. 4. In the last sentence of the last paragraph, “would” should be replaced by “must”. 5. The Drafting Team should reconsider the use of “Load” as opposed to “Demand”. By definition (NERC Glossary dated April 20, 2010) Demand is: 1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.” Load is defined as: “An end-use device or customer that receives power from the electric system.” This terminology is more appropriate to the application used in the Table. Possible rewording of footnote “b” to be considered: b) Under the limited circumstances when interruption of Load is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Load that is directly served by the elements that are removed from service as a result of the Contingency o Interruptible Load or Demand-Side Management o Demand that does not adversely impact overall BES reliability where the circumstances for the use of such Load interruption and alternatives evaluated are documented. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of available resources, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions must also be respected.
Individual
David Kiguel
Hydro One Networks Inc.
No
1. The introductory paragraph discourages the Interruption of any Demand, implying that no Demand directly connected should be interrupted. However, it is an acceptable practice to allow for some Interruption of Demand that is directly connected to the element that is removed from service. Recommend that the drafting team revise the wording to eliminate this implication, and soften the expectation such that it is recognized that some Interruption of Demand is unavoidable by system configuration, but that each entity should establish a reasonable limit on how much demand can be interrupted due to the loss of an element. 2. The Statement that “However, Demand may need to be interrupted in limited circumstances to address BES performance requirements” in the introductory paragraph contradicts bullet 3 “Demand that does not adversely affect BES …” 3. The third Bullet is confusing. Suggest revising the wording to clarify the adverse impact to the BES system, documentation expectations, and to answer fundamental questions such as who has the authority to decide the use if the stakeholder process is “accepting”, and the necessity of having a stakeholder process. It is unlikely that the interruption of Demand will adversely impact the BES system. This constraint is too broad. The language in this bullet also allows that non-consequential Demand interruption could be used to mitigate reliability violations arising from the NERC Category B contingency events (i.e., single element contingencies). 4. In the second paragraph, the conditions when interruption of Firm Transfers may be used are not specified. 5. In the last sentence of the second paragraph, “would” should be replaced by “must”. Alternatively, possible rewording of footnote “b” to be considered: b) An objective of the planning process should be to minimize the likelihood of interrupting Demand and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements or other local reasons which have no adverse impact on overall BES reliability or the interconnected BES. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Demand that does not adversely impact overall reliability of the BES or the interconnected BES and where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of available resources, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected. The Drafting Team should reconsider the use of “Load” as opposed to “Demand”. By definition (NERC Glossary dated April 20, 2010) Demand is: “1. The rate at which electric energy is

delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer." Load is defined as: "An end-use device or customer that receives power from the electric system." This terminology is more appropriate to the application used in the Table.
Individual
Jason Marshall
Midwest ISO
No
Overall, we believe the changes are reasonable. However, we propose to strike "and where the application is subject to review and acceptance in an open and transparent stakeholder process." Stakeholder review processes should not be mandated through enforceable standards as they do not provide a clear benefit to reliability. Further, FERC Order 890 already mandates an open and transparent process related to the planning of the bulk electric system.
Individual
Claudiu Cadar
GDS Associates Inc.
No
We appreciate all the work conducted by SDT to adjust current footnote "b" however, we disagree with the current approach as follows below: - The definition does not go far enough with recognition that interruption of Demand should be mitigated if at all possible. The previous language may have been inadequate, but the current language does not encourage the TP to develop mitigation plans that could be implemented as an alternative to Demand interruption. - Use of Interruptible Demand should only be implemented if the Transmission Planner can point to a contract between the Transmission Provider and Transmission Customer that permits load curtailment. - Under FERC Order 890, Conditional Firm transmission service can be granted for entities who voluntarily acknowledge the right of the Transmission Provider to curtail their transaction or provide re-dispatch. This should be the only transfer which can be utilized in the Planning Horizon for interruption of Demand for Note b. Suggested language to find the balance point in the tone of this note is below: "An objective of the planning process is to develop mitigation plans that do not call for the curtailment of Demand, as interruption of Demand places specific customer groups at a reliability risk that varies from their counterparts in other areas of the BES. There may be rare instances, however, where interruption of Demand can be considered a short-term bridge to a mitigation plan which does not rely on negatively impacting certain customer segments. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency, o Interruptible Demand or Demand-Side Management, where the Customer has given explicit rights to the Transmission Provider for curtailment of their Demand, o Demand, other than Interruptible Demand or Demand-Side Management, that does not adversely impact overall BES reliability where the circumstances describing the use of such Demand are documented, including alternatives evaluated; where the Load-Serving Entity who has responsibility for serving such Demand has agreed to the curtailment, and where the application is subject to review and acceptance in an open and transparent stakeholder process. Curtailment of Firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch per the terms and conditions of the confirmed transmission service request between the Transmission Customer and Transmission Provider, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of and firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected. In addition, any Conditional Firm transfers may be curtailed, in accordance with the terms and conditions of the confirmed transmission service request between the Transmission Customer and Transmission Provider."
Individual
Chifong Thomas
Pacific Gas and Electric Co.
Yes
Group
IRS Standards Review Committee
Ben Li
Yes
Individual
Catherine Koch
Puget Sound Energy
Yes
PSE agrees with the foot note b as stated. As it states for any category B outage there wouldn't be any non-

consequential load loss allowed unless a full study is performed with evaluation of alternatives and is approved by stakeholders. Also, one could curtail firm transfers if re-dispatch of resource is possible. However, there is still some ambiguity in when approval from stakeholders (time-line)should be sought and who the stakeholders could be (customers, effected utilities etc.). Hence, PSE would like to revise the footnote by adding the following to the end of the footnote, ".... at least 2 years prior to the implementation. All the affected parties must review and agree upon the loss of demand proposal."
Group
IRC Standards Review Committee
Ben Li
Yes
Individual
Harold Wyble
Kansas City Power & Light
No
KCPL appreciates the efforts of the Assess Transmission Future Needs SDT in reaching a reasonable proposal for clarifying Table 1 footnote B presented in the TPL-001 through TPL-004 standards. We also commend NERC staff for convening an industry technical conference to discuss the topic and FERC staff for their participation in the technical conference as the industry carefully considered various perspectives. Although the proposed footnote B is much improved from the prior draft proposals, KCPL proposes is to strike the text following the semicolon in the third bullet item which states “and where the application is subject to review and acceptance in an open and transparent stakeholder process.” This text may be intended as explanatory but has the appearance of mandating an approval process that will be auditable through the TPL reliability standards. The statement is not needed within the framework of mandatory reliability requirements as FERC Order 890 already mandates an open and transparent process related to the planning of the bulk electric system. FERC via the 890 Final Rule modified the pro forma Open-Access Transmission Tariff to require open and transparent stakeholder process to better ensure no undue discrimination and access to the transmission system. The Final Rule beginning at paragraph 418 discusses reform to the Coordinated, Open and Transparent Planning of the transmission system. The Commission direction included eight planning principles required to be within the open process – one of which is dispute resolution. It should be well understood that the transmission planner and planning coordinator share and disseminate all of their planning study results and proposed corrective actions – including the proposed use of Demand interruption – as part of their adherence to Order 890.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on TPL Table 1 Order (footnote 'b') — Project 20010-11

The TPL Table 1 Order Drafting Team thanks all commenters who submitted comments on the revised footnote. These standards were posted for a 30-day informal public comment period from September 8, 2010 through October 8, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 42 sets of comments, including comments from more than 96 different people from approximately 75 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

Comments can be reviewed in their original format on the following project page:

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Industry response was divided in relation to support for the proposed footnote 'b' which was posted for an informal comment period through October 8, 2010. Although there were a number of supporters for the proposed footnote they were outnumbered by the commenters who did not support the footnote text for various reasons and offered their views and concerns.

The Standard Drafting Team (SDT) carefully considered the feedback provided including minority opinions such as not allowing Demand interruption at all and has made clarifying revisions to the footnote 'b' text.

The revised footnote 'b' is:

b) An objective of the planning process ~~is to avoid~~ should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. ~~Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process~~. However, it is recognized that Demand ~~may need to~~ will be interrupted if it is directly served by the elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- ~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~
- Interruptible Demand or Demand-Side Management
- ~~Demand that does not adversely impact overall BES reliability where the c~~Circumstances ~~describing~~ where the use of ~~such~~ Demand interruption are documented, including alternatives evaluated; and where the ~~application~~ Demand interruption is subject to review ~~and acceptance~~ in an open and transparent stakeholder process that includes addressing stakeholder comments.

Based on the review of comments received and the fact that only clarifying changes were made due to those comments, the SDT is recommending that this project be moved forward to balloting.

If you feel that your comment has been overlooked, 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]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, 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, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council	10									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Micahel Schiavone	National Grid	NPCC	1
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Dean Ellis	Dynegy Generation	NPCC	5
8.	Brian Evans-Mongeon	Utility Services	NPCC	8
9.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
10.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	Chantel Haswell	FPL Group, Inc.	NPCC	5
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1
14.	Michael R. Lombardi	Northeast Utilities	NPCC	1

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

15.	Randy MacDonald	New Brunswick System Operator	NPCC	2
16.	Bruce Metruck	New York Power Authority	NPCC	6
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	Saurabh Saksena	National Grid	NPCC	1

2.	Group	Philip R. Kleckley	SERC Planning Standards Subcommittee	1, 3, 5

Additional Member	Additional Organization	Region	Segment Selection	
1.	Bob Jones	Southern Company Services - Trans	SERC	1
2.	John Sullivan	Ameren	SERC	1
3.	Charles Long	Entergy	SERC	1
4.	Jim Kelley	PowerSouth Energy Cooperative	SERC	1
5.	Pat Huntley	SERC Reliability Corporation		10

3.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	WPS Corporation	MRO	3, 4, 5, 6
4.	Jason Marshall	Midwest ISO Inc.	MRO	2
5.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
6.	Ken Goldsmith	Alliant Energy	MRO	4
7.	Alice Murdock	Xcel Energy	MRO	1, 3, 5, 6
8.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
9.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
10.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
11.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
12.	Scott Nickels	Rochester Public Utilties	MRO	4
13.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment
4.	Group	Denise Koehn	Bonneville Power Administration	1, 3, 5, 6

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chuck Matthews	BPA, Transmission Planning	WECC	1
2.	Berhanu Tesema	BPA, Transmission Planning	WECC	1
3.	Kyle Kohne	BPA, Transmission Planning	WECC	1
4.	Kendall Rydell	BPA, Transmission Planning	WECC	1
5.	Rebecca Berdahl	BPA, Long Term Sales and Purchases	WECC	3

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment
5.	Group	Louis Slade, Jr.	Dominion	1, 3, 5, 6

	Additional Member	Additional Organization	Region	Segment Selection
1.	Angela Park	Electric Transmission	SERC	1, 3
2.	John Loftis	Electric Transmission	SERC	1, 3
3.	Mike Garton	Electric Market Policy	NPCC	5, 6
4.	Michael Gildea	Electric Market Policy	RFC	5, 6

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment
6.	Group	Ben Li	IRC Standards Review Committee	2

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Phillips	MISO	MRO	2
2.	Partick Brown	PJM	RFC	2
3.	James Castle	NYISO	NPCC	2
4.	Mark Thompson	AESO	WECC	2
5.	Charles Yeung	SPP	SPP	2
6.	Greg Van Pelt	CAISO	WECC	2
7.	Matt Goldberg	ISO-NE	NPCC	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Individual	Jana Van Ness	Arizona Public Service Company	X		X		X					
8.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
9.	Individual	John Cummings	PPL Corp	X		X		X					
10.	Individual	Andy Tillery	Southern Company	X		X							
11.	Individual	Don Gilbert	JEA	X		X		X					
12.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
13.	Individual	Laura Zotter	ERCOT ISO		X								
14.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
15.	Individual	Steve Stafford	Georgia Transmission Corporation	X									
16.	Individual	John Canavan	NorthWestern Energy	X									
17.	Individual	Tim Ponseti	TVA Transmission Planning & Compliance	X		X		X				X	
18.	Individual	Gordon Rawlings	BC Hydro	X	X	X		X					
19.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				
20.	Individual	John Sullivan	Ameren	X		X		X	X				
21.	Individual	Darcy O'Connell	California ISO		X								
22.	Individual	Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
23.	Individual	Orlando A Ciniglio	Idaho Power	X		X		X					
24.	Individual	Michael Lombardi	Northeast Utilities	X		X		X					
25.	Individual	Thad Ness	American Electric Power	X		X		X	X				
26.	Individual	JC Culberson	ERCOT		X								
27.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
28.	Individual	Charles Lawrence	American Transmission Company	X									
29.	Individual	Kathleen Goodman	ISO New England Inc.		X								
30.	Individual	Dan Rochester	Independent Electricity System Operator		X								
31.	Individual	Ed Davis	Entergy Services	X		X		X	X				
32.	Individual	Terry Harbour	MidAmerican Energy	X		X		X	X				
33.	Individual	Patrick Farrell	Southern California Edison Company	X		X		X	X				
34.	Individual	Jonathan Appelbaum	United Illuminating Co	X									
35.	Individual	Michael Moltane	ITC	X									
36.	Individual	Gregory Campoli	New York Independent System Operator		X								
37.	Individual	David Kiguel	Hydro One Networks Inc.	X		X							
38.	Individual	Jason Marshall	Midwest ISO		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
39.	Individual	Claudiu Cadar	GDS Associates Inc.	X									
40.	Individual	Chifong Thomas	Pacific Gas and Electric Co.	X		X		X					
41.	Individual	Catherine Koch	Puget Sound Energy	X									
42.	Individual	Harold Wyble	Kansas City Power & Light	X		X		X	X				

1. **The SDT is proposing a revision to footnote 'b' in the TPL tables to comply with FERC Orders which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Do you agree with the proposed changes and if not, please provide specific reasons for your disagreement.**

Summary Consideration: Industry response was divided in relation to support for the proposed footnote 'b' which was posted for an informal comment period through October 8, 2010. Although there were a number of supporters for the proposed footnote they were outnumbered by the commenters who did not support the footnote text and offered their views and concerns.

The Standard Drafting Team (SDT) carefully considered the feedback provided and has made clarifying revisions to the footnote 'b' text. For each major item, the SDT has addressed the issue raised and has summarized any revision made to footnote 'b' in response to the feedback provided. The SDT appreciates industry input and believes the changes made are responsive to the comments received.

Open and Transparent Process: Most of the comments received related to the use of an "open and transparent" stakeholder process as described in the proposed footnote 'b'. While the comments on this topic varied, the majority of comments indicated that such a process should not be included within a mandatory Reliability Standard and cited that FERC Order 890 already requires the sharing of planning information. Others indicated that the statement for "review and acceptance" exceeds expectations required by FERC Order 890 and that an entity's compliance to a Reliability Standard should not be subject to the "acceptance" of stakeholders and that a process conforming with FERC Order 890 principles already requires dispute resolution. Some commenters expressed support of the process and it is noted that those who responded "Yes" with no comment were assumed to support the process "as is".

The SDT's inclusion of a stakeholder review in footnote 'b' was driven by the fact that FERC Order 890 does not fully cover the continent-wide footprint addressed by a NERC Reliability Standard. Additionally, footnote 'b' is being applied to address localized Bulk Electric System performance and not a wide-area Bulk Electric System concern that is generally the focus of the "open and transparent" process governed by FERC Order 890.

The SDT thoroughly considered all comments on the stakeholder process model. The SDT continues to support a Reliability Standard providing mandatory enforcement utilizing a stakeholder process where any intended use of planned Demand interruption has transparency and that stakeholders have the opportunity to comment on its use. However, upon further reflection the majority of SDT members agreed that including the "acceptance" aspect of the stakeholder process presents challenges within the context of a Reliability Standard and "acceptance" has been removed. The SDT agrees with opinions that an entity's compliance should not be subject to the "acceptance" of its plans by stakeholders. Also, the SDT realizes that for most entities there is a final, high level review with acceptance or approval of Transmission plans at the local level. So, while the footnote no longer references the need for stakeholder acceptance, the expectation is that there will be a review process in place that will consider the implementation of any plan calling for Demand interruption as explained in the footnote.

In addition, the SDT has revised footnote 'b' to explicitly require a response to any challenges presented via the stakeholder process.

Demand vs. Load: Several commenters questioned the SDT's use of the term "Demand" instead of "Load" in the proposed footnote. The SDT clarifies that this was intentional as the existing, approved TPL suite of standards uses the term Demand throughout the requirement text. Additionally, the existing, approved TPL performance requirements documented in Table I contain the column heading "Loss of Demand or Curtailed Firm Transfers" which is the subject of the footnote 'b' applicability for category B (single element) Contingencies. This project, Project 2010-11, aims to address footnote 'b' regulatory directives with no change to the remainder of the standard. Therefore, for consistency with the existing standard text, the term Demand is retained.

Firm transfer vs. Firm Transmission Service: Some stakeholders suggested that the SDT revert back to the use of "Firm Transmission Service" instead of the undefined term "firm transfers." The SDT clarifies that that the change to "firm transfers" was intentional as the existing, approved TPL suite of standards references "firm transfers" both in requirement text and Table I. The existing, approved TPL performance requirements documented in Table I contain the column heading "Loss of Demand or Curtailed Firm Transfers" which is the subject of the footnote 'b' applicability for category B (single element) Contingencies. This project, Project 2010-11, aims to address footnote 'b' regulatory directives with no change to the remainder of the standard. Therefore for consistency with the existing standard text, the term 'firm transfer' is retained.

Amount of Demand Loss: The majority of commenters agree with the SDT's clarifications regarding interruption of Demand as defined in the proposed footnote 'b'. The majority of entities who commented support the limited use of Demand interruption and that when used to address a BES performance requirement agree that it should be documented, and made known through a stakeholder process. However, as stated above, the majority stopped short of supporting a mandatory Reliability Standard requiring "acceptance" by other entities for the planned interruption of Demand.

Other minority views propose to limit or cap the amount of Demand loss and some suggested 50 MW as the appropriate level. Some felt the SDT's prior approach of limiting the Demand loss to only "radial" line configurations was appropriate and superior to the "open process" approach. It is also noted that some commenters went further to say no loss of Demand should be allowed for a single Contingency, but this was clearly a minority view of the comments submitted.

The SDT carefully considered the comments and unanimously agreed that defining a Demand level limit is problematic based on the vast differences in BES applications across the continent and that each potential use is case specific. The SDT also had concerns that setting such a limit may have the unintended consequences of planned Demand interruption being more widely accepted in practice in Transmission planning. The SDT and most commenters are of the opinion that a stakeholder review process is a better deterrent for Demand interruption and will appropriately guard against any misuse.

The revised footnote 'b' is:

b) An objective of the planning process ~~is to avoid~~ should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. ~~Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process~~. However, it is recognized that Demand ~~may need to~~ will be interrupted if it is directly served by the elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- ~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~
- Interruptible Demand or Demand-Side Management
- ~~Demand that does not adversely impact overall BES reliability where the c~~Circumstances ~~describing~~ where the use of ~~such~~ Demand interruption are documented, including alternatives evaluated; and where the ~~application~~ Demand interruption is subject to review ~~and acceptance~~ in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	1. The introductory paragraph discourages the Interruption of any Demand, implying that no Demand directly connected should be interrupted. However, it is an acceptable practice to allow for some Interruption of Demand that is directly connected to the element that is removed from service. Recommend that the drafting team revise the wording to eliminate this implication, and soften the expectation such that it is recognized that some Interruption of Demand is unavoidable by system configuration, but that each entity should establish a reasonable limit on how much demand can be interrupted due to the loss of an element. 2. The Statement that "However, Demand may need to be interrupted in limited circumstances to address BES performance requirements" in the introductory paragraph contradicts bullet 3 "Demand that does not adversely affect BES ..." 3. The third Bullet is confusing. Suggest revising the wording to clarify the adverse impact to the BES system, documentation expectations, and to answer fundamental questions such as who has the authority to decide the use if the stakeholder process is "accepting", and the necessity of having a stakeholder process. It is unlikely that the interruption of Demand will adversely impact the BES system. This constraint is too broad. The language in this bullet also allows that non-consequential Demand interruption could be used to mitigate reliability violations arising from the NERC Category B contingency events (i.e., single element contingencies). 4. In the second paragraph, the conditions when interruption of Firm Transfers may be used are not specified. 5. In the last sentence of the second paragraph, "would" should be replaced by "must". Alternatively, possible rewording of footnote "b" to be considered: b) An objective of the planning process should be to minimize the likelihood of interrupting Demand and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements or other local reasons which have no adverse impact on overall BES reliability or the interconnected BES. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Demand that does not adversely impact overall reliability of the BES or the interconnected BES and where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of available resources, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected. The Drafting Team should reconsider the use of "Load" as opposed to "Demand". By definition (NERC

Organization	Yes or No	Question 1 Comment
		Glossary dated April 20, 2010) Demand is:"1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer."Load is defined as:"An end-use device or customer that receives power from the electric system."This terminology is more appropriate to the application used in the Table.
Hydro One Networks Inc.	No	1. The introductory paragraph discourages the Interruption of any Demand, implying that no Demand directly connected should be interrupted. However, it is an acceptable practice to allow for some Interruption of Demand that is directly connected to the element that is removed from service. Recommend that the drafting team revise the wording to eliminate this implication, and soften the expectation such that it is recognized that some Interruption of Demand is unavoidable by system configuration, but that each entity should establish a reasonable limit on how much demand can be interrupted due to the loss of an element. 2. The Statement that "However, Demand may need to be interrupted in limited circumstances to address BES performance requirements" in the introductory paragraph contradicts bullet 3 "Demand that does not adversely affect BES ..." 3. The third Bullet is confusing. Suggest revising the wording to clarify the adverse impact to the BES system, documentation expectations, and to answer fundamental questions such as who has the authority to decide the use if the stakeholder process is "accepting", and the necessity of having a stakeholder process. It is unlikely that the interruption of Demand will adversely impact the BES system. This constraint is too broad. The language in this bullet also allows that non-consequential Demand interruption could be used to mitigate reliability violations arising from the NERC Category B contingency events (i.e., single element contingencies). 4. In the second paragraph, the conditions when interruption of Firm Transfers may be used are not specified. 5. In the last sentence of the second paragraph, "would" should be replaced by "must". Alternatively, possible rewording of footnote "b" to be considered: b) An objective of the planning process should be to minimize the likelihood of interrupting Demand and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements or other local reasons which have no adverse impact on overall BES reliability or the interconnected BES. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Demand that does not adversely impact overall reliability of the BES or the interconnected BES and where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of available resources, where it can be demonstrated that Facilities remain within

Organization	Yes or No	Question 1 Comment
		applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected. The Drafting Team should reconsider the use of "Load" as opposed to "Demand". By definition (NERC Glossary dated April 20, 2010) Demand is:"1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer."Load is defined as:"An end-use device or customer that receives power from the electric system."This terminology is more appropriate to the application used in the Table.
SERC Planning Standards Subcommittee	No	The revised text relating to the planning process exceeds what is appropriate for a reliability standard. Existing open and transparent stakeholder processes focus on larger system issues and not on local load serving. We suggest the following: Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Interruptible Demand or Demand-Side Management o Demand that does not adversely impact overall BES reliability and is made temporarily radial as a result of the Contingency, where that Demand must be interrupted to meet performance requirements. Curtailment of firm transfers is allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected. " The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers."
Ameren	No	The revised text to footnote b relating to the planning process exceeds what is appropriate for a reliability standard. Existing open and transparent stakeholder processes focus on larger system issues rather than on local load serving issues. We suggest the following text for footnote b:Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Interruptible Demand or Demand-Side Management o Demand that does not adversely impact overall BES reliability and is made temporarily radial as a result of the Contingency, where that Demand must be interrupted to meet performance requirements. Curtailment of firm transfers is allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the

Organization	Yes or No	Question 1 Comment
		re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.
MRO's NERC Standards Review Subcommittee	No	The revised draft is a significant improvement over the first draft. However, we suggest the following minor changes: 1. The criterion of "adversely affect overall BES reliability" is undefined and maybe subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest adding the words "as defined by each Transmission Planner or Planning Authority". 2. The term of "firm transfers" is undefined and maybe subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest establishing a definition for the term, reverting to the "Firm Transmission Service" term, or using another appropriate defined term.
American Transmission Company	No	The revised draft is a significant improvement over the first draft. However, we suggest the following minor changes: 1. The criterion of "adversely affect overall BES reliability" is undefined and may subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest adding the words "as defined by each Transmission Planner or Planning Authority". 2. The term of "firm transfers" is undefined and may subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest establishing a definition for the term of "firm transfers", reverting to the "Firm Transmission Service" term, or using another appropriate NERC defined term.
PacifiCorp	No	PacifiCorp believes that the current version of footnote "b" is an improvement over the language that currently exists in the standard, except for one component of the revised footnote. The third bullet in the draft standard currently limits the interruption of Demand if it does not adversely impact overall BES reliability, where the circumstances describing the use of the interruption are documented (including alternatives evaluated) and the application is subject to review and acceptance in "an open and transparent stakeholder process." PacifiCorp believes that the language requiring review and acceptance of an application of demand interruption through any sort of stakeholder process should be removed. It is not practical or effective to prescribe that either this standard or any other standard requires stakeholder approval in order to maintain compliance. As presently drafted, this requirement for stakeholder review and acceptance appears to be inconclusive and indeterminate as to what is required for registered entities to comply. Instead, this third bullet should require the documentation, by the Planning Authority and Transmission Planner, of the circumstances describing the use of Demand interruption - including methodologies used, assumptions relied upon, and alternatives evaluated - as part of the Planning Authorities' and/or Transmission Planners'

Organization	Yes or No	Question 1 Comment
		documentation of results in their annual Reliability Assessments. These annual assessments are already submitted to the appropriate Regional Reliability Organization pursuant to TPL-002-1b Requirement R3. This annual assessment can be provided by the ERO to other appropriate third parties upon their request.
Southern Company	No	The revised text relating to the planning process exceeds what is appropriate for a reliability standard. Existing open and transparent stakeholder processes focus on larger system issues and not on local load serving. We suggest that the drafting team go back to the concept of local load being the load that is made temporarily radial by the contingency. That was a much better approach.
JEA	No	The requirement in general is acceptable; however, there needs to be an added "such as" clause to the referenced "...in an open and transparent stakeholder processes." I suggest adding "..."...in an open and transparent stakeholder processes such as the FERC approved regional 890 process that includes the load serving entity affected".
South Carolina Electric and Gas	No	SCE&G believes the first sentence "An object of the planning process is to avoid interruption of Demand." goes beyond what is appropriate for a reliability standard and therefore should be deleted. Also, the part of the sentence that states "and where the application is subject to review and acceptance in an open and transparent stakeholder process" goes beyond what is appropriate for a reliability standard and should be deleted.
NorthWestern Energy	No	In addition to the three bullet items, add a fourth bullet item to the list of limitations under the body of footnote b: “In no case will a total loss of load that is less than 50 MW be considered a violation of this standard.”
TVA Transmission Planning & Compliance	No	TVA supports FERC's actions on improving reliability of the BES; however, TVA believes that the new proposal is focusing more on reliability of local loads than on the overall reliability of the BES. Footnote b should focus only on the overall reliability of the BES. Reliability of local loads should be addressed outside the TPL standards and therefore should not be used/referenced in footnote b. Also existing stakeholder processes (referred to in the SDT proposal) typically focus on larger system issues and not on local load serving. Thus TVA believes that some local load should be allowed to be dropped in order to maintain BES reliability. However TVA does believe that there should be a limit of how much load can be dropped in order to maintain BES reliability. TVA believes that 50 MW is a reasonable number for this limit. Based on the above, TVA proposes substituting the following for the revised footnote b:Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: Demand that is directly served by the elements that are removed from service as a result of the Contingency Interruptible Demand or Demand-Side Management Demand that does not adversely impact overall BES reliability, where that Demand (not to exceed 50 MW)

Organization	Yes or No	Question 1 Comment
		must be interrupted to meet performance requirements. Curtailment of firm transfers is allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.
BC Hydro	No	The SDT is to be commended for their efforts to develop clear, unambiguous language for Footnote "b". From the discussions that have taken place it seems that there are many different perspectives and to get agreement on specific language will be very difficult. We believe that it would be useful to identify the main issues that Footnote "b" needs to address and we consider those main issues to be: o Definitions of (a) Consequential Load Loss, (b) Firm Demand, (c) Firm Transmission Capability (as distinct from the OATT term, "Firm Transmission Service"), (d) Firm Transfer (this could be defined as transfers using the OATT's Firm Transmission Service, (e) Manual System Adjustments (capitalized in the Category C section of TPL-001, but not defined in the NERC Glossary) and (f) the Bulk Electric System (BES). o Identifying permissible Demand/Transfer curtailment actions for (a) the planning studies simulating the Category B event itself and (b) the planning studies associated with determining acceptable actions for preparing for the next set of contingencies should the initial single contingency be prolonged (ie, last several weeks). This would define the acceptable (pre-emptive) "Manual System Adjustments" of Category C events. o Define separate acceptable curtailment actions for (a) curtailment of Demand (ie, end-user load) and (b) curtailment of market to market transfers, that very rarely, if ever, result in the loss of any end-user load. o Define the planning studies required to determine the acceptability of the impacts on the BES resulting from curtailments in a "remote" part of the system that have been accepted by those directly affected by those curtailments. At this point we don't have specific language to suggest, but we do have the following comments that we hope will help: A. Interruption of Demand: A.1. Consider improving the definition of "Firm Demand" in the NERC Glossary that now reads, "That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions". Perhaps it could be changed to something like, "That portion of the Demand that the planned transmission system must be able to supply without interruption for Category B events. A.2. Consider stating in Footnote "b" that curtailment of Firm Demand is (a) not permitted in the simulation of the N-1 event itself and (b) it is not permitted as part of the (pre-emptive) "Manual System Adjustments" needed to prepare for the next set of contingencies should the initial single contingency be prolonged (ie, last

Organization	Yes or No	Question 1 Comment
		several weeks). B. Interruption of Firm Transfers: B.1. "Firm Transfers" could be defined as transfers using the OATT's Firm Transmission Service, but consider developing a system reliability-based term for "Firm Transmission Capability" instead of referring to the tariff-based NERC definition of "Firm Transmission Service". This would recognize the difference between planning standards and commercial/tariff rules. The NERC definition of "Firm Transmission Service" is now, "The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption". Transmission tariffs address the priority of curtailments when the loading on a transmission path needs to be reduced for whatever reason (single- or multiple-contingencies). The NERC transmission planning standards need a system reliability definition like, "Firm Transmission Capability" is the transmission capability across a cut-plane, on a defined transmission path or across a defined flowgate that is available, before any manual corrective actions are taken, following the worst Category B event under the most onerous normal system conditions considering all plausible generation dispatch patterns and the full range of expected load levels." B.2. Consider stating in Footnote "b" that curtailment of Firm Transfers is only permitted to the extent that redispatch of generation can be implemented so that delivery to the Firm Transfer recipient is not interrupted (a) in the planning studies of the Category B event itself and (b) as part of the (pre-emptive) "Manual System Adjustments" needed to prepare for the next set of contingencies should the initial single contingency be prolonged (ie, last several weeks). C. General Comments: C.1. Consider replacing the first bullet of the proposed Footnote "b" with simply "Consequential Load Loss" since the NERC Project 2006 02 (TPL 001) Standard Drafting Team is introducing the following definition: Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault C.2. Consider removing "Demand-Side Management" (DSM) from the second bullet because that term is too general. The present definition of DSM in the NERC Glossary is:"The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use". C.3. Consider being more specific on what constitutes acceptable "Interruptible Demand", like: "Interruptible Demand that is part of an automatic real-time Direct Control Load Management (DCLM) system that is activated by the contingencies that require it and that is a completely "dual-redundant" scheme including all communications equipment. The DCLM system must result in automatic curtailment of Demand that is fast enough to maintain all BES system performance standards (eg, voltage stability, voltage dip, etc)".

Organization	Yes or No	Question 1 Comment
		C.4. Consider eliminating the description of how interrupting Demand that does not adversely impact overall BES reliability was accepted (ie, the stakeholder process, etc). If such a process were undertaken and it resulted in acceptance that the Demand could be curtailed for Category B events, wouldn't that simply mean that the Demand was "Interruptible Demand". It really doesn't matter what process resulted in it being accepted. The key considerations are that (a) if the interruption of that Demand is necessary to maintain BES reliability, then it must be interrupted in a very reliable manner (ie, dual redundant scheme, etc) and (b) if the interruption of that Demand is not necessary to maintain the reliable performance of the BES, then that should be confirmed by the planning studies (ie, it doesn't need to have an expensive, sophisticated, dual-redundant DCLM scheme since the impact on the BES is acceptable even if the scheme doesn't work). D. Additional Questions related to Curtailment of Firm Transfers: In the past, the latter part of Footnote B read: "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers."The last part of the proposed Footnote B now reads: "Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected."We would like to understand the implications of the proposed Footnote B as it relates to curtailment of Firm Transfers (as per definition proposed earlier) for the following questions: 1) In the most recent draft of Footnote B, why was the NERC defined term 'Firm Transmission Service' replaced with the non-defined term 'firm transfers'? 2) In the most recent draft of Footnote B, why was the tone softened from "No curtailment of Firm Transmission Service is allowed, except..." to "Curtailment of firm transfers is allowed when..."? 3) Assuming an outage of a single transmission line (N-1 Category B event) has occurred and assuming that no "resources [are] obligated to redispatch" for this outage, would a transmission provider be allowed to curtail Firm Transmission Service (NERC defined term) that it has sold in order to prepare to withstand the next worst credible contingency? 4) Would transmission providers be allowed to sell Firm Transmission Service on a path above what could be delivered with any one element of that path out of service and a range of operating conditions? 5) If the proposed Footnote B is approved, would utilities have to reinforce their system (within 60 months) to ensure that Firm Transmission Service for particular paths would not be curtailed can be delivered when any one element of that path is out of service? 6) If a transmission provider employs Generation Dropping for single contingencies in order to support Firm Transmission Service between regions, and assuming there are no provisions for obligated re-dispatch, would

Organization	Yes or No	Question 1 Comment
		the proposed Footnote B force a recalculation of firm vs non-firm transfer capability? 7) Path 66 (PACI) and Path 65 (PDCI) can both see significant derates in their firm transfer capability for single contingencies. How would the proposed Footnote B impact Firm Transmission on these paths?
FirstEnergy	No	FirstEnergy appreciates the efforts of the Assess Transmission Future Needs SDT in reaching a reasonable proposal for clarifying Table 1 footnote B presented in the TPL-001 through TPL-004 standards. We also commend NERC staff for convening an industry technical conference to discuss the topic and FERC staff for their participation in the technical conference as the industry carefully considered various perspectives. The proposed footnote B is much improved from the prior draft proposals. One change that FirstEnergy proposes is to strike the text following the semicolon in the third bullet item which states "and where the application is subject to review and acceptance in an open and transparent stakeholder process." This text may be intended as explanatory but has the appearance of mandating an approval process that will be auditable through the TPL reliability standards. The statement is not needed within the framework of mandatory reliability requirements as FERC Order 890 already mandates an open and transparent process related to the planning of the bulk electric system. FERC via the 890 Final Rule modified the pro forma Open-Access Transmission Tariff to require open and transparent stakeholder process to better ensure no undue discrimination and access to the transmission system. The Final Rule beginning at paragraph 418 discusses reform to the Coordinated, Open and Transparent Planning of the transmission system. The Commission direction included eight planning principles required to be within the open process - one of which is dispute resolution. It should be well understood that the transmission planner and planning coordinator share and disseminate all of their planning study results and proposed corrective actions - including the proposed use of Demand interruption - as part of their adherence to Order 890. We appreciate the SDT's careful consideration of our comments.
Northeast Utilities	No	NU agrees with the language of the proposed revision to Footnote b EXCEPT FOR bullet #3 which suggests that non-consequential demand interruption could be used to mitigate reliability violations arising from the NERC Category B contingency events (i.e., single element contingencies).
ERCOT	No	The introductory paragraph of footnote b includes policy language. Since this is a reliability standard-and not a policy directive-the general narrative setting forth the desired policy goal of minimizing load-shedding is misplaced. Including policy language can cloud the specific issues the standard attempts to address, and ERCOT recommends deleting the first two sentences in the introductory paragraph. The next sentence in the introductory paragraph goes on to state, generally, that demand may be interrupted to "address BES performance requirements." This phrase is vague. To which performance requirements does this refer? The intent is not clear. If the intent is to generally recognize the need to shed load to respect

Organization	Yes or No	Question 1 Comment
		NERC standards and to allow flexibility for an entity to exercise discretion relative to meeting BES performance requirements, then that intent should be clearly reflected in the language. Furthermore, the last sentence of the introductory paragraph and the subsequent bullet points are arguably inconsistent with this approach, because they could be viewed as removing an entity's flexibility/discretion by limiting the circumstances when load can be shed. The second bullet point is unnecessary, because it is already apparent that interruptible demand/demand side management programs can be used according to their terms. This could create confusion in that it could be implied that, absent the need to use these to meet BES performance requirements, using them otherwise is inconsistent with/not allowed under footnote b. Simply put, those products are not load shedding as contemplated by this footnote. Therefore they should not be listed here. With respect to the third bullet point, the phrase "demand that does not adversely impact overall BES reliability" is not adequately defined, and provides opportunity for confusion. This is an ambiguous phrase and can't be linked back to objective NERC standards/requirements. The bullet points should avoid ambiguity to mitigate ambiguity risk in audits. In addition, the last part of the language in this bullet imposing an open and transparent stakeholder process is unclear. What is the intent behind requiring review in a stakeholder process? If it is to establish the ability of the entity to develop load shedding procedures beyond those explicitly contemplated in footnote b, ERCOT questions if it is reasonable for the responsible entity to be required to get "permission" from stakeholders to implement reliability measures related to its obligation as the functional entity. Again, the language simply is not clear. Accordingly, ERCOT recommends this bullet point be removed. If it is retained, it should be revised consistent with these comments to remove ambiguous language to mitigate potential confusion around the meaning/scope of the footnote in the administration of the CMEP. In addition, ERCOT recommends revising the draft footnote b to allow for planned Demand interruption as a means of mitigation during interim periods when a unanticipated (such as unexpected demand growth or unit retirements) or temporary change on the system occurs in a timeframe that is shorter than the time necessary to plan and implement the system upgrades necessary to avoid the Demand interruption. Finally, in the last paragraph of footnote b, it isn't clear why "Transmission Service" was changed to "transfers." Firm transmission service is a service provided in some regions, and it provides relative value to other types of services-e.g., non-firm and network. The mention of transmission service may also be irrelevant in this footnote, since the allowance of its interruption doesn't also allow for load shedding. Therefore, ERCOT recommends eliminating the last paragraph of footnote b.
ISO New England Inc.	No	ISO New England does not allow non-consequential load loss for first contingencies in Planning Analysis, and as an overall matter, ISO-NE believes that the appropriate step is for NERC to modify the footnote in line with

Organization	Yes or No	Question 1 Comment
		the original FERC Order. However, ISO-NE offers the following recommendation to improve the proposed language for footnote b if it is to be retained similar to what has been proposed. In short, ISO-NE proposes changing the third sub-bullet, because the provision is both unnecessary and inappropriate for a NERC Standard. First, the sub-bullet is redundant, because the Commission has ordered that companies add to their Open Access Transmission Tariffs an open and transparent planning process. If Transmission Planners establish their system planning assessments through those processes, then there should be no question that the Planner’s assessments have been effectively communicated to the region. Second, the passive nature of the language (i.e., “where the application is subject to review and acceptance...”) is unclear as it suggests that someone other than the Planning Coordinator/Transmission Planner is responsible for determining what belongs in a long-term system assessment. Including Demand-Side Management in the standard also appears redundant as Demand Response is used as an asset in the same manner as generation resources. b) When interruption of Demand is utilized within the planning process, such interruption is limited to: 1) Demand that is directly served by the elements that are removed from service as a result of the Contingency. 2) Interruptible Demand or Demand-Side Management 3) Instances where the planned or controlled interruption of Demand results in System performance which meets the requirements of Table 1 for Category B contingencies. When such Demand interruption is utilized in an assessment, the use of such actions must be limited to small portions of the system, be operationally achievable, be of limited duration, and be documented therein.
Entergy Services	No	Entergy disagrees with the proposed language in the third bullet for two reasons. 1. While Entergy supports the idea of “an open and transparent stakeholder process” regarding the use of non-consequential load loss. It is unclear how such a process could be fairly implemented as competing stakeholder interests could prevent resolution. Stakeholders should be defined as those stakeholders whose load could be shed per footnote b, not any and all stakeholders. 2. The “is subject to review and acceptance” implies that some formal voting process would be required by stakeholders. Is this the SDT’s intent? If so would such a process be developed as part of the standard or would it be left up to TO’s? If non-consequential load loss was deemed an acceptable solution across a SEAM, would the TO’s jointly serving the load need to agree?

Organization	Yes or No	Question 1 Comment
MidAmerican Energy	No	While the TPL note “b” approach has improved, MidAmerican has concerns that including the wording “review and acceptance” goes beyond the FERC Order 890 order, process, and intent of including the open review process. Therefore, to align with FERC Order 890, the “review and acceptance” should be replaced with “subject to comment”. Anything more exceeds FERC Order 890 and the reason why the review process was included. In the end, Transmission Owning and Operating entities must have final say in the operation of the grid. Entities can comment, but cannot obstruct Transmission Owning and Operating entities from properly operating the grid or reliability could be reduced.
United Illuminating Co	No	United Illuminating believes that for TPL Category B contingencies no planned or controlled (non-consequential) interruption of firm demand should occur as a general philosophy for planning the Bulk Electric System (BES). Recognizing there are certain areas of the BES that have unique circumstances that may warrant an exception to this, UI suggests the addition of language that recognizes the limited application of non-consequential load interruption with a process that requires a case-by-case acceptance of such application by the Regional Entity or NERC.
New York Independent System Operator	Yes	The NYISO agrees in principle with the proposed changes, but recommends the following modifications: 1. The introductory paragraph discourages the Interruption of any Demand, implying that no Demand directly connected should be interrupted. However, it is an acceptable practice to allow for some Interruption of Demand that is directly connected to the element that is removed from service. The introductory paragraph is immaterial to the requirement, and therefore unnecessary with the exception of the last sentence which starts the bulleted list. 2. Interruptible demand is an operation tool and not a transmission planning tool, while Demand-Side Management is typically embedded in the load forecast used in the planning process. The second bullet therefore may not be necessary or applicable here, though it is helpful in making clear those are acceptable forms of interruption. 3. The third bullet is confusing. Suggest revising the wording to clarify the adverse impact to the BES system and documentation expectations. Recommend removing reference to the application being subject to review and acceptance in an open and transparent stakeholder process; this is inherent to all documentation and does not need to be emphasized in a footnote. 4. In the last sentence of the last paragraph, “would” should be replaced by “must”. 5. The Drafting Team should reconsider the use of “Load” as opposed to “Demand”. By definition (NERC Glossary dated April 20, 2010) Demand is: 1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.”Load is defined as:”An

Organization	Yes or No	Question 1 Comment
		end-use device or customer that receives power from the electric system."This terminology is more appropriate to the application used in the Table. Possible rewording of footnote "b" to be considered: b) Under the limited circumstances when interruption of Load is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Load that is directly served by the elements that are removed from service as a result of the Contingency o Interruptible Load or Demand-Side Management o Demand that does not adversely impact overall BES reliability where the circumstances for the use of such Load interruption and alternatives evaluated are documented. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of available resources, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must also be respected.
Midwest ISO	No	Overall, we believe the changes are reasonable. However, we propose to strike "and where the application is subject to review and acceptance in an open and transparent stakeholder process." Stakeholder review processes should not be mandated through enforceable standards as they do not provide a clear benefit to reliability. Further, FERC Order 890 already mandates an open and transparent process related to the planning of the bulk electric system.
GDS Associates Inc.	No	We appreciate all the work conducted by SDT to adjust current footnote "b" however, we disagree with the current approach as follows below:- The definition does not go far enough with recognition that interruption of Demand should be mitigated if at all possible. The previous language may have been inadequate, but the current language does not encourage the TP to develop mitigation plans that could be implemented as an alternative to Demand interruption. - Use of Interruptible Demand should only be implemented if the Transmission Planner can point to a contract between the Transmission Provider and Transmission Customer that permits load curtailment .- Under FERC Order 890, Conditional Firm transmission service can be granted for entities who voluntarily acknowledge the right of the Transmission Provider to curtail their transaction or provide re-dispatch. This should be the only transfer which can be utilized in the Planning Horizon for interruption of Demand for Note b. Suggested language to find the balance point in the tone of this note is below:"An objective of the planning process is to develop mitigation plans that do not call for the curtailment of Demand, as interruption of Demand places specific customer groups at a reliability risk that varies from their counterparts in other areas of the BES. There may be rare instances, however, where interruption of Demand can be considered a short-term bridge to a mitigation plan which does not rely on negatively impacting certain customer segments. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency, o

Organization	Yes or No	Question 1 Comment
		Interruptible Demand or Demand-Side Management, where the Customer has given explicit rights to the Transmission Provider for curtailment of their Demand, o Demand, other than Interruptible Demand or Demand-Side Management, that does not adversely impact overall BES reliability where the circumstances describing the use of such Demand are documented, including alternatives evaluated; where the Load-Serving Entity who has responsibility for serving such Demand has agreed to the curtailment, and where the application is subject to review and acceptance in an open and transparent stakeholder process. Curtailment of Firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch per the terms and conditions of the confirmed transmission service request between the Transmission Customer and Transmission Provider, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of and firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected. In addition, any Conditional Firm transfers may be curtailed, in accordance with the terms and conditions of the confirmed transmission service request between the Transmission Customer and Transmission Provider.”
Kansas City Power & Light	No	KCPL appreciates the efforts of the Assess Transmission Future Needs SDT in reaching a reasonable proposal for clarifying Table 1 footnote B presented in the TPL-001 through TPL-004 standards. We also commend NERC staff for convening an industry technical conference to discuss the topic and FERC staff for their participation in the technical conference as the industry carefully considered various perspectives. Although the proposed footnote B is much improved from the prior draft proposals, KCPL proposes is to strike the text following the semicolon in the third bullet item which states “and where the application is subject to review and acceptance in an open and transparent stakeholder process.” This text may be intended as explanatory but has the appearance of mandating an approval process that will be auditable through the TPL reliability standards. The statement is not needed within the framework of mandatory reliability requirements as FERC Order 890 already mandates an open and transparent process related to the planning of the bulk electric system. FERC via the 890 Final Rule modified the pro forma Open-Access Transmission Tariff to require open and transparent stakeholder process to better ensure no undue discrimination and access to the transmission system. The Final Rule beginning at paragraph 418 discusses reform to the Coordinated, Open and Transparent Planning of the transmission system. The Commission direction included eight planning principles required to be within the open process - one of which is dispute resolution. It should be well understood that the transmission planner and planning coordinator share and disseminate all of their planning study results and proposed corrective actions - including the proposed use of Demand interruption - as part of their adherence to Order 890.
Puget Sound Energy	Yes	PSE agrees with the foot note b as stated. As it states for any category B outage there wouldn't be any non-consequential load loss allowed unless a full study is performed with evaluation of alternatives and is approved by stakeholders. Also, one could curtail firm transfers if re-dispatch of resource is possible.

Organization	Yes or No	Question 1 Comment
		However, there is still some ambiguity in when approval from stakeholders (time-line) should be sought and who the stakeholders could be (customers, effected utilities etc.). Hence, PSE would like to revise the footnote by adding the following to the end of the footnote, ".... at least 2 years prior to the implementation. All the affected parties must review and agree upon the loss of demand proposal."
Southern California Edison Company	Yes	SCE appreciates the efforts of the NERC Standards Drafting Team and believes that the team has admirably worked to meet FERC's expectations.SCE would suggest that Footnote "b" be revised to include a semi-colon(;) after the first sub-paragraph and a semi-colon(;) followed by an "and" after the second sub-paragraph, to convey that the three sub-paragraphs are alternative, rather than additive methods for satisfying the requirements for "interruptions."
Idaho Power	Yes	footnote 'b' is silent with respect to planned removal from service of certain generators. I believe there are many conditions out there where a single contingency can initiate a planned (RAS-initiated) removal of generation. The fact that this is mentioned in footnote 'c', under multiple contingencies, begs the need for futher elaboration/discussion of this option under single contingencies in footnote 'b'.
Manitoba Hydro	Yes	The changes to Table 1 Note b proposed by the SDT for this second posting are a reasonable approach to the issue of interrupting of “Firm Demand”. The requirement to evaluate alternatives to dropping of Firm Demand in a transparent stakeholder process should provide the verification of cost over benefit on a case by case basis. I propose the following editorial changes: 1. The change of “Firm Transmission Services” made in Table 1 should be also be made in each TPL standard as R1 refers to “projected Firm (non-recallable reserved) Transmission Services.2. Since “Firm Demand” is a defined term, ensure it is capitalized throughout the standard. There is one instance where it is not.
California ISO	Yes	1) Regarding the 2nd bullet provision, we suggest: Interruptible Demand or Demand-Side Management that has been reviewed and approved by the Planning Authority. 2) Regarding the 3rd bullet provision, we suggest: Demand interruption that does not adversely impact overall BES reliability.... 3) Also regarding the 3rd bullet provision, we suggest replacing acceptance with clarification to read “where the application is subject to review and clarification in an open and transparent stakeholder process."
Xcel Energy	Yes	Xcel Energy supports the new interpretation that would allow curtailment of firm transfers or demand for limited conditions where the integrity of bulk electric system is not compromised. However Xcel Energy seeks some clarification regarding the following: The 3rd bullet point in footnote b will need to clarify whether the demand interruption can be done after the contingency, or before the contingency. If it is allowed after the

Organization	Yes or No	Question 1 Comment
		contingency, then the standard would allow violation of voltage or thermal loading criteria for a brief period, after contingency and, before demand curtailment happens. Is this acceptable based on the new interpretation? Since TPL-002 standard deals with NERC Category B contingencies, and footnote b states that curtailment of firm transfers is allowed, it should be clarified if this curtailment is allowed before or after the contingency. If the curtailment is allowed only after the contingency, then the system would be in violation of the thermal or voltage criteria for a brief period till the generation is re-dispatched. Is this allowed by the new interpretation? If curtailment is only allowed in preparation of the contingency, then the firm transfers would be curtailed during system intact conditions, in preparation for the first contingency, resulting in violation of TPL-001 standard. Is this allowed by the new interpretation?
PPL Corp	Yes	PPL believes that Footnote b as described in TPL-002-1b, Draft 2, August 30, 2010 is fine provided an accompanying Requirement (with appropriate VRF and VSL) and Measure is added to the TPL standard(s) to require and document notification of the affected Demand parties and the involvement of the affected Demand parties in an open process as described by Footnote b, third bullet.
Duke Energy	Yes	Duke Energy strongly supports this revised footnote ‘b’. We believe that it provides for appropriate consideration of stakeholder input in decision-making for local reliability issues, while maintaining the reliability of the Bulk Electric System.
ITC	Yes	The proposed language for the new TPL-001-1 Table 1 footnote b is acceptable to ITC.
Bonneville Power Administration	Yes	
Dominion	Yes	
IRS Standards Review Committee	Yes	
IRC Standards Review Committee	Yes	
Arizona Public Service Company	Yes	
ERCOT ISO	Yes	

Organization	Yes or No	Question 1 Comment
Georgia Transmission Corporation	Yes	
American Electric Power	Yes	
Independent Electricity System Operator	Yes	
Pacific Gas and Electric Co.	Yes	

Unofficial Comment Form for TPL Table 1 Order (Project 2010-11)

Please **DO NOT** use this form to submit comments on the 3rd posting for Project 2010-11: TPL Table 1 Order. Please use the electronic comment form posted on the following project page:

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

The electronic comment form must be completed by **January 5, 2011.** This is a 45-day formal comment period.

If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Background Information

The Standard Drafting Team (SDT) posted Table I, footnote 'b' for an informal comment period from September 8, 2010 through October 8, 2010. Industry response was divided in relation to support for the proposed footnote 'b.' Although there were a number of supporters for the proposed footnote they were outnumbered by the commenters who did not support the footnote text for various reasons and offered their views and concerns.

The SDT carefully considered the feedback provided including minority opinions such as not allowing Demand interruption at all and has made clarifying revisions to the footnote 'b' text.

The revisions made to footnote 'b' following the informal comment period are shown below:

b) An objective of the planning process ~~is to avoid~~ should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. ~~Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process~~. However, it is recognized that Demand ~~may need to~~ will be interrupted if it is directly served by the elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- ~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~
- Interruptible Demand or Demand-Side Management
- ~~Demand that does not adversely impact overall BES reliability where the c~~Circumstances ~~describing~~ where the use of ~~such~~ Demand interruption are documented, including alternatives evaluated; and where the ~~application~~ Demand interruption is subject to review ~~and acceptance~~ in an open and transparent stakeholder process that includes addressing stakeholder comments.

Please Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The SDT is proposing a revision to footnote 'b' in the TPL tables to comply with a FERC directive which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Do you agree with the proposed changes and if not, please provide specific reasons for your disagreement.

   ☐ Yes

   ☐ No

   Comments:

A. Introduction

1. Title: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. Number: TPL-004-1

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-1_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-1_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

<table>
<tr><th rowspan="2">Category</th><th>Contingencies</th><th colspan="3">System Limits or Impacts</th></tr>
<tr><th>Initiating Event(s) and Contingency Element(s)</th><th>System Stable and both Thermal and Voltage Limits within Applicable Rating [a]</th><th>Loss of Demand or Curtailed Firm Transfers</th><th>Cascading Outages</th></tr>
<tr><td>A
No Contingencies</td><td>All Facilities in Service</td><td>Yes</td><td>No</td><td>No</td></tr>
<tr><td rowspan="2">B
Event resulting in the loss of a single element.</td><td>Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:
1. Generator
2. Transmission Circuit
3. Transformer
Loss of an Element without a Fault.</td><td>Yes
Yes
Yes
Yes</td><td>No [b]
No [b]
No [b]
No [b]</td><td>No
No
No
No</td></tr>
<tr><td>Single Pole Block, Normal Clearing[e]:
4. Single Pole (dc) Line</td><td>Yes</td><td>No[b]</td><td>No</td></tr>
<tr><td rowspan="5">C
Event(s) resulting in the loss of two or more (multiple) elements.</td><td>SLG Fault, with Normal Clearing[e]:
1. Bus Section
2. Breaker (failure or internal Fault)</td><td>Yes
Yes</td><td>Planned/ Controlled[c]
Planned/ Controlled[c]</td><td>No
No</td></tr>
<tr><td>SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]:
3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency</td><td>Yes</td><td>Planned/ Controlled[c]</td><td>No</td></tr>
<tr><td>Bipolar Block, with Normal Clearing[e]:
4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]:
5. Any two circuits of a multiple circuit towerline[f]</td><td>Yes
Yes</td><td>Planned/ Controlled[c]
Planned/ Controlled[c]</td><td>No
No</td></tr>
<tr><td>SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure):
6. Generator
7. Transformer
8. Transmission Circuit
9. Bus Section</td><td>Yes
Yes
Yes
Yes</td><td>Planned/ Controlled[c]
Planned/ Controlled[c]
Planned/ Controlled[c]
Planned/ Controlled[c]</td><td>No
No
No
No</td></tr>
</table>

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- Interruptible Demand or Demand-Side Management
- Circumstances where the uses of such Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

A. Introduction

1. Title: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. Number: TPL-004-1

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote ‘b’ in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority’s and Transmission Planner’s assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-1_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-1_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process ~~is to avoid~~ should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. ~~Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process.~~ However, it is recognized that Demand ~~may need to~~will be interrupted if it is directly served by the Elements removed from service as a result of the contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- ~~Demand that is directly served by the elements that are removed from service as a result of the Contingency, or~~
- Interruptible Demand or Demand-Side Management
- ~~Demand that does not adversely impact overall BES reliability where the c~~Circumstances ~~describing~~ where the uses of such Demand interruption are documented, including alternatives evaluated; and where the ~~application~~ Demand interruption is subject to review ~~and acceptance~~ in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

A. Introduction

1. Title: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. Number: TPL-004-~~0~~1

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

~~**5. Effective Date:** April 1, 2005~~

5. Effective Date: The application of revised Footnote ‘b’ in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority’s and Transmission Planner’s assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-~~0~~1_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-~~0~~1_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

~~b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- Interruptible Demand or Demand-Side Management
- Circumstances where the uses of such Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

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. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Informal comment period completed October 8, 2010.

Proposed Action Plan and Description of Current Draft:

This is the third draft of the proposed modification to footnote ‘b’ posted for a 45-day formal comment period, with an initial ballot to be conducted during the last 10 days of the comment period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Initial ballot	December 2010
2. Recirculation ballot	January 2011
3. Submit to BOT for approval	January 2011
4. File with FERC	February 2011

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**
2. **Number:** TPL-003-1a
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
4. **Applicability:**
   4.1. Planning Authority
   4.2. Transmission Planner
5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-1_R1 and TPL-003-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information
None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
1a	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- Interruptible Demand or Demand-Side Management
- Circumstances where the uses of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

A. Introduction

1. Title: System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)

2. Number: TPL-003-1a

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote ‘b’ in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-1_R1 and TPL-003-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
1a	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process ~~is to avoid~~ should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. ~~Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process.~~ However, it is recognized that Demand ~~may need to~~ will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements,, such interruption is limited to:

- ~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~
- Interruptible Demand or Demand-Side Management
- ~~Demand that does not adversely impact overall BES reliability where the c~~Circumstances ~~describing~~ where the uses of ~~such~~ Demand interruption are documented, including alternatives evaluated; and where the ~~application~~ Demand interruption is subject to review ~~and acceptance~~ in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-~~0~~1a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

~~5. **Effective Date:** April 1, 2005~~

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-~~0~~1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-~~0~~1_R1 and TPL-003-~~0~~1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-~~0~~1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
1a	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	 Yes Yes Yes Yes	 Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	 No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

~~b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- o Interruptible Demand or Demand-Side Management
- o Circumstances where the uses of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2
Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

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. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Informal comment period completed October 8, 2010.

Proposed Action Plan and Description of Current Draft:

This is the third draft of the proposed modification to footnote ‘b’ posted for a 45-day formal comment period, with an initial ballot to be conducted during the last 10 days of the comment period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Initial ballot	December 2010
2. Recirculation ballot	January 2011
3. Submit to BOT for approval	January 2011
4. File with FERC	February 2011

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-1b

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-1_R1 and TPL-002-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	April 2010	Revised footnote 'b' pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- Interruptible Demand or Demand-Side Management
- Circumstances where the uses of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-1b

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-1_R1 and TPL-002-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	April 2010	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process ~~is to avoid~~ should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. ~~Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process.~~ However, it is recognized that Demand ~~may need to~~ will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- ~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~
- Interruptible Demand or Demand-Side Management
- ~~Demand that does not adversely impact overall BES reliability where the c~~Circumstances ~~describing~~ where the uses of ~~such~~ Demand interruption are documented, including alternatives evaluated; and where the ~~application~~ Demand interruption is subject to review ~~and acceptance~~ in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

> **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.

Background Information for Interpretation

Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations:

1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)."
2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)."
3. "Include the effects of existing and planned protection systems, including any backup or redundant systems."

Category B of Table 1 (single Contingencies) specifies:

Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:

1. Generator
2. Transmission Circuit
3. Transformer

Loss of an Element without a Fault.

Single Pole Block, Normal Clearing[e]:

4. Single Pole (dc) Line

Note e specifies:

e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."

Conclusion

TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations.

This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

A. Introduction

1. **Title:** **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. **Number:** TPL-002-~~0~~1b

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

~~5. **Effective Date:** April 1, 2005~~

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories~~,~~, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-~~0~~1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-~~0~~1_R1 and TPL-002-~~0~~1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-~~0~~1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	April 2010	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section - - - - - - - - - - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - - - - - - - - - - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

~~b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- Interruptible Demand or Demand-Side Management
- Circumstances where the uses of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.

Background Information for Interpretation

Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations:

1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)."
2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)."
3. "Include the effects of existing and planned protection systems, including any backup or redundant systems."

Category B of Table 1 (single Contingencies) specifies:

Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:

1. Generator
2. Transmission Circuit
3. Transformer

Loss of an Element without a Fault.

Single Pole Block, Normal Clearing[e]:

4. Single Pole (dc) Line

Note e specifies:

e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."

Conclusion

TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations.

This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

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. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Informal comment period completed October 8, 2010.

Proposed Action Plan and Description of Current Draft:

This is the third draft of the proposed modification to footnote ‘b’ posted for a 45-day formal comment period, with an initial ballot to be conducted during the last 10 days of the comment period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Initial ballot	December 2010
2. Recirculation ballot	January 2011
3. Submit to BOT for approval	January 2011
4. File with FERC	February 2011

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)

2. **Number:** TPL-001-1

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

    4.1. Planning Authority

    4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-1_R1 and TPL-001-1_ R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:			
	1. Generator	Yes	No [b]	No
	2. Transmission Circuit	Yes	No [b]	No
	3. Transformer	Yes	No [b]	No
	Loss of an Element without a Fault	Yes	No [b]	No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]:			
	1. Bus Section	Yes	Planned/ Controlled[c]	No
	2. Breaker (failure or internal Fault)	Yes	Planned/ Controlled[c]	No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]:			
	4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]:	Yes	Planned/ Controlled[c]	No
	5. Any two circuits of a multiple circuit towerline[f]	Yes	Planned/ Controlled[c]	No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure):			
	6. Generator	Yes	Planned/ Controlled[c]	No
	7. Transformer	Yes	Planned/ Controlled[c]	No
	8. Transmission Circuit	Yes	Planned/ Controlled[c]	No
	9. Bus Section	Yes	Planned/ Controlled[c]	No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- Interruptible Demand or Demand-Side Management
- Circumstances where the uses of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is

due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)

2. **Number:** TPL-001-1

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-1_R1 and TPL-001-1_ R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D[d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process ~~is to avoid~~ should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. ~~Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process~~. However, it is recognized that Demand ~~may need to~~ will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- ~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~
- Interruptible Demand or Demand-Side Management
- ~~Demand that does not adversely impact overall BES reliability where the c~~Circumstances ~~describing~~ where the uses of ~~such~~ Demand interruption are documented, including alternatives evaluated; and where the ~~application~~ Demand interruption is subject to review ~~and acceptance~~ in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)

2. **Number:** TPL-001-~~0~~1

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

~~5. **Effective Date:** April 1, 2005~~

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-~~0~~1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-~~0 R2.~~1 R1 and TPL-001-~~0~~1 R2~~.2~~.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-~~0~~1 R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
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0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
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1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

~~b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- Interruptible Demand or Demand-Side Management
- Circumstances where the uses of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Implementation Plan for Project 2010-11: TPL Table 1 Order

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

Revision to Sections of Approved Standards and Definitions

There are no new definitions in the proposed standards.

Compliance with Standards

Standards	Functions That Must Comply With the Associated Requirements	
	Transmission Planner	Planning Authority
TPL-001-0.2: System Performance Under Normal (No Contingency) Conditions (Category A) TPL-002-0c: System Performance Following Loss of a Single Bulk Electric System Element (Category B) TPL-003-0b: System Performance Following Loss of Two or More Bulk Electric System Elements (Category C) TPL-004-0a: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)	X	X

Effective Dates

The effective date is the date entities are expected to meet the performance identified in this standard.

The effective date for footnote 'b' will be the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption.

All other requirements remain in effect as per previous approvals.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Ballot Pool Open November 19 – December 22, 2010
Comment Period Open November 19 – January 5, 2011

Now available at: http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

TPL Table 1, Footnote B SAR (Project 2010-11)

The TPL Table 1 Order Drafting Team is seeking comments on Table 1 footnote 'b' in TPL-001-1 through TPL-004-1 until **8 p.m. EDT on January 5, 2011.**

FERC's Order in docket RM06-16-009 requires the ERO to clarify TPL-002-0, Table 1- footnote 'b,' regarding the planned or controlled interruption of electric supply, where a single contingency occurs on a transmission system, and originally directed NERC to file the revised standards by June 30, 2010. To meet this directive, a proposed revision was posted for "Urgent Action" and balloted from May 17-27, 2010. The proposed revision achieved a quorum (84%) and almost enough affirmative votes (64%) to achieve weighted segment approval; however, many balloters provided comments indicating the need for additional modifications. Following the initial ballot, FERC extended the due date to March 31, 2011; thus the project is no longer considered "Urgent Action."

Because Table 1 appears in TPL-001, TPL-002, TPL-003, and TPL-004, the change is reflected in all four standards:

- TPL-001-1 - System Performance Under Normal (No Contingency) Conditions (Category A)
- TPL-002-1b - System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- TPL-003-1a - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
- TPL-004-1 - System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

Ballot Pool (through December 22, 2010)

Because of the length of time between the last ballot (May 2010) and the time of the upcoming ballot (December 2010, many members of the initial ballot pool are no longer in the Registered Ballot Body. The existing ballot pool has been dissolved and a **new ballot pool** is being formed to vote on the proposed revision to Table 1, footnote 'b.' Registered Ballot Body members may join this new ballot pool to be eligible to vote on these proposed modifications **until 8 a.m. EDT on December 22, 2010**.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2010-11_TPL_Table_1_in

Comment Period (through January 5, 2011)

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page:

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Next Steps

An initial ballot will be conducted during the last 10 days of the formal comment period. The drafting team will consider all comments (those submitted with a comment form, and those submitted with a ballot) and will determine whether to make additional changes to the standards. The team will post its response to comments and, if the standards have only minor changes, will post the standards and conduct a 10-day recirculation ballot.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

Individual or group. (27 Responses)
Name (21 Responses)
Organization (21 Responses)
Group Name (6 Responses)
Lead Contact (6 Responses)
Question 1 (27 Responses)
Question 1 Comments (27 Responses)

-
Group
Arizona Public Service Company
Janet Smith
No
It is not clear whether both bullets under "footnote b" have to be met or only one of the two have to be met. It is suggested that the standard be very clear about this.
Group
Northeast Power Coordinating Council
Guy Zito
No
There is concern with the use of the term Demand. It is unclear throughout the footnote whether or not the term Demand includes Interruptible Demand or Demand-Side Management. It is suggested that interruption of Demand be clarified to not include Interruptible Demand or Demand-Side Management to more clearly show the permitted use of Load shedding. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. Language that mitigation of Load and/or Demand interruption should be pursued within the planning process should be reinstated as reinforcement of a Transmission Providers' planning obligations to their load customers, and system operations. Footnote 'b' should be made to read as follows: b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of Load and/or Demand following Contingency events. Interruption of Load and/or Demand is discouraged and all measures to mitigate such interruption should be pursued within the planning process. However, it is recognized that Load and/or Demand will be interrupted if it is directly served by the elements automatically removed from service by the Protection System as a result of a Contingency. Furthermore, in extraordinary circumstances within the planning process Load and/or Demand may need to be interrupted to address BES performance requirements. When interruption of Load and/or Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: • Circumstances where the use of Load and/or Demand interruption are documented, including alternatives evaluated; and where the Load and/or Demand interruption is made available for review in an open and transparent stakeholder process. If Load and/or Demand interruption is necessary, planning should indicate the amount needed, and not specify how it would be obtained. What Load and/or Demand is interrupted is an operational decision. Additional comments not included in the material listed for footnote 'b' on the Comment Form. In the paragraph below the bullets in footnote 'b', confusion is introduced through the use of the term "firm Demand". It is unclear how this is different than the defined term "Firm Demand" and what the implications of the term "firm Demand" are. This footnote should not discourage such adjustments which actually increase the reliability of service to end users. The last sentence of footnote 'b' is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own.
Individual
Aaron Staley
Orlando Utilities Commission
No
The current language provides a balance between the end goal of reliablity (no load loss for B events) and the practical constraint that project cost may outweigh the benefit. Two things are unclear though. Item one: The standard team should clarify if the bullets under note B are intended to be an AND (both conditions met) or an OR (either condition met). As currently written it is not clear. Item #2: The section under firm transfers is in conflict with the section above. If Demand is being curtailed under the first or second bullet and it's served by firm service then service should also be curtailed, however as written any demand served by firm service could not be curtailed.
Individual
Greg Rowland
Duke Energy
Yes
The effective date in the Implementation Plan needs to be changed to match the Effective Date in the standards, in

order to clarify the allowed interruption of Non-consequential load before the new Footnote ‘b’ takes effect.
Individual
Si Truc PHAN
Hydro-Quebec TransÉnergie
Yes
Paragraph should be more clear as: b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances within the planning process, Demand may need to be interrupted to address BES performance requirements. In such case : o Only Interruptible Demand or Demand-Side Management are allowed; o Circumstances where the uses of Demand interruption is needed shall be documented, compared to alternatives, and reviewed in an open and transparent stakeholder process that address stakeholder comments. Curtailment of firm transfers is allowed, when coupled with the appropriate and necessary re-dispatch of resources where it can be demonstrated that this does not result in the shedding of any firm Demand and that Facilities remain within applicable Facility Ratings, including Facilities external to the Transmission Planner’s planning region when they are relied upon.
Group
SERC Planning Standards Subcommittee
Charles W. Long
No
The PSS agrees that the proposed language for footnote b provides some additional clarity. While we generally support the concept, we have concerns that the phrase “is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments” remains ambiguous and should be clarified by limiting stakeholder input to those who have load at risk or local regulators obligated to act on their behalf. Revise the first sentence of the last paragraph to read: “To prepare for a second contingency, curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand.” The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Individual
Tim Ponseti, VP
TVA Trasnmission Plannning & Compliance
No
TVA appreciates the SDT’s efforts to clarify and improve this complex and challenging area. However, as mentioned in our last comments regarding footnote b, TVA still believes that the SDT’s proposal is still focusing more on reliability of local loads than on the overall reliability of the BES. Reliability of local loads should be addressed outside the TPL standards and therefore should not be used/referenced in footnote b. Existing stakeholder processes (referred to in the SDT proposal) typically focus on larger system issues and not on local load serving. TVA believes that some local load should be allowed to be dropped in order to maintain BES reliability. Instead of the proposed footnote b, TVA suggests that the SDT define a “local area” with guidelines detailing the reliability requirements for these local area loads. This would separate the local area load requirements from the BES requirements in the TPL standards.
Individual
Alex Rost
New Brunswick System Operator
No
NBSO agrees with the principles of the current version of the proposed footnote, as far as NBSO’s interpretation of the footnote is correct. NBSO has the following detailed comments: 1. The first paragraph contains many general statements that attempts to capture essential planning principles. NBSO feels that such language is not suited for a footnote. NBSO suggests re-wording of the first paragraph to state: Interruption of Demand may be utilized within the planning process to address BES performance requirements. Such cases are limited to: NBSO also suggests turning the phrase that addresses Demand lost that was served by elements removed from service as a result of a Contingency into a bullet item. NBSO feels that this adds clarity since all of the acceptable instances of Demand interruption are now listed as bulleted items. 2. NBSO interprets that the currently proposed footnote allows for the two bulleted options to be used exclusively or in combination. Thus for clarification NBSO suggests adding “or” after each bulleted item, with the exclusion of the final bulleted item. 3. NBSO suggests removing the last sentence of the last paragraph. Likely all industry members understand that causing reliability concerns in other areas is never acceptable. This principle is not limited to the standard in question, and thus such a statement could require the update of other standards. 4. NBSO interprets that the use of the word “Demand” in the second bullet of the proposed footnote is referring to use of Firm Demand since the first bullet covers the other types of Demand (Demand = Firm Demand + Interruptible Demand). As such NBSO suggests replacing “Demand” with “Firm Demand” in the second bullet. 5. NBSO

feels that the statement “that includes addressing stakeholder comments” should be removed from the last phrase of the second bullet. An open and transparent stakeholder process should adequately address stakeholder comments and concerns. Explicitly specifying that all stakeholder comments be addressed may add undue burden if the word “address” is misconstrued. The task of addressing stakeholder comments is more appropriately addressed and defined in each area’s respective process. 6. NBSO suggests replacing the word “shedding” with “interruption” in the last phrase of the last paragraph to remain consistent with the rest of the proposed footnote. NBSO also suggests capitalizing “firm” in the term “Firm Demand” to remain consistent with the NERC glossary of terms. 7. There is no term “transfers” in the NERC glossary of terms. Perhaps some other defined term from the glossary could be used in lieu of “transfers” (e.g. Firm Transmission Service). Taking into account the NBSO comments, the footnote could read as follows: b) Interruption of Demand may be utilized within the planning process to address BES performance requirements. Such cases are limited to: -Demand directly served by Elements removed from service as a result of a Contingency, or -Use of Interruptible Demand or Demand-Side Management, or -Interruption of Firm Demand when acceptable circumstances for such interruptions are documented (including alternatives evaluated), and where the Firm Demand interruption is subject to review in an open and transparent stakeholder process. Curtailment of Firm Transmission Service is allowed when coupled with the appropriate re-dispatch of resources obligated to do so, and it can be demonstrated that Facilities remain within applicable Facility Ratings and there is no additional interruption of Firm Demand.
Individual
Joe Petaski
Manitoba Hydro
No
The last bullet should be made clearer by adding the words “in jurisdictions” before the word “where”. Not all jurisdictions are mandated to have a stakeholder process, so the standard should be clearly written to recognize this situation. "Circumstances where the use of Demand interruption are documented, including alternatives evaluated; and IN JURISDICTIONS where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments."
Group
PacifiCorp
Sandra Shaffer
Yes
appreciates the efforts of the SDT and supports revision of TLP-002-0 Table 1 footnote “b” as stated in this draft.
Individual
Bernie Pasternack
Transmission Strategies, LLC
Yes
Individual
Michael A. Curtis, General Counsel
Mohave Electric Cooperative
Yes
Group
MRO's NERC Standards Review Subcommittee
Carol Gerou
Yes
Individual
David Thorne
Pepco Holding Inc
Yes
Individual
John Sullivan
Ameren
No
We agree with the statement that an objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following single contingency events. While we appreciate the drafting team’s

efforts in removing the need for acceptance by other parties in the stakeholder process, we still feel that language in the second bullet of the revised footnote b should be modified to remove all references to an open and transparent stakeholder process. Existing RTO stakeholder processes that we are aware of focus on larger system issues, rather than on local load serving issues. Therefore, we believe that the load serving issues following single contingency events are issues between the customer and the utility, and should be addressed in one-on-one forums between those entities.
Individual
Thad Ness
American Electric Power
Yes
Individual
Bob Casey
Georgia Transmission Corporation
Yes
Individual
Alice Ireland
Xcel Energy
No
As this is currently drafted, planners would be required to host a forum with stakeholders to discuss hypothetical actions that may be taken in an emergency. We do not see the value in this, nor is it clear who would be considered stakeholders that should attend this forum. For example, we assume it would be the transmission owner's meeting with distribution providers to discuss the possibility of load shedding. Would that be adequate? Xcel Energy is both a Transmission Planner and a Distribution Provider. In this case would the stakeholder be the end user? This should be struck or more clearly defined.
Individual
Saurabh Saksena
National Grid
No
National Grid supports the direction the drafting team has taken. However, it has a few concerns with the language of the footnote as amended. 1. Use of the term "Demand": In the first sentence, it is unclear whether the term Demand includes Interruptible Demand and Demand-Side Management. It is suggested that interruption of Demand be clarified to exclude Interruptible Demand or Demand-Side Management. 2. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. 3. National Grid also suggests changing "Demand interruption" to "interruption of Demand" in second bullet under "b)" to avoid awkward and incorrect phasing. 4. 'Addressing stakeholder comments' introduces undefined actions which may be required in response to the comments. If 'Demand interruption is subject to review in an open and transparent stakeholder process', then stakeholder comments will be addressed without creating an undefined commitment to require it. As a result, "that includes addressing stakeholder comments" should be deleted. 5. The second paragraph seems to be restricting the use of Demand interruption for the sake of Firm Transfer reduction. This can be stated directly without adding the confusion of re-dispatch. By coupling re-dispatch with a constraint of not shedding Demand, the paragraph also creates confusion as to what to do in a situation where the amount of Demand that is allowed to be shed in the first paragraph could be reduced with re-dispatch. Would re-dispatch not be allowed? National Grid suggests that the paragraph be rewritten as follows: 'Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management).' 6. National Grid seeks clarification if there is an intended distinction between the use of the term "firm Demand" and the defined term "Firm Demand" or is that just a typo? 7. The last sentence of footnote B is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own. This same thought would have to be added to multiple NERC standards if it were added here, otherwise it would infer that such actions are acceptable in all other standards.
Individual
Andrew Z. Pusztai
American Transmission Company
Yes
Individual
Jason L. Marshall

Midwest ISO
Yes
Group
Southern Company
Andy Tillery
No
Southern Company is voting "no" on the footnote b ballot because of concerns that the reliability of firm transfers could be compromised. The existing Table I Transmission System Standards, which have been in place as early as the 1997 NERC Planning Standards, do not allow Loss of Demand or Curtailed Firm Transfers under single (Category B) contingencies. Footnote B addressed two areas: 1) the loss of radial or local network load, which Southern Company agrees that the drafting team has appropriately clarified and 2) preparing for the next contingency, which Southern Company does not agree has been appropriately clarified. Southern Company believes the proposed wording "Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch" now allows for the curtailment of firm transfers for single contingencies, whereas Southern Company did not believe this was previously permitted under the standards. Southern Company interprets the new language to allow a planner to curtail firm transfers (generation) to address a single contingency. Southern Company interpreted the original language to not permit the curtailment of firm transfers (generation) for a single contingency, but rather that a planner would develop a suitable transmission reinforcement or other mitigation. Southern Company is concerned that the proposed language could result in a degradation in the dependability of firm transfers impacting the reliability of those customers who rely upon them. Southern Company agrees that a system reconfiguration including the redispatch of generation is appropriate when preparing for a second contingency (Category C). Therfore, a distinction is needed between what is allowed in response to a first contingency and what is allowed to be prepared for a second contingency. The curtailment of firm transfers should not be allowed as a response to the first contingency. This practice would undermine the concept of firm transfers. The curtailment of firm transfers should only be allowed in footnote b as a system adjustment to be prepared for a second contingency. We propose the following to clarify that curtailments are permitted only to prepare for the second contingency. "To prepare for the next contingency, curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch".
Individual
Michael Lombardi
Northeast Utilities
No
The revised language of Footnote b suggests that non-consequential demand interruption (load that is not directly served by the elements removed from service as a result of the contingency) could be used to mitigate reliability concerns arising from NERC Category B contingency events (i.e., single element contingencies). This language seems to encourage operational workarounds and adds burdens for operators of the system. NU believes this is not consistent with planning a highly reliable bulk electric system and thus does not support this weaker language.
Individual
Dan Rochester
Independent Electricity System Operator
Yes
Individual
Gregory Campoli
New York Independent System Operator
No
Proposed revised footnote language: b) It is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Interruptible Demand or Demand-Side Management o Circumstances where the uses of firm Demand interruption not directly interrupted by the contingency are documented, including alternatives evaluated; and where the firm Demand interruption is subject to review in an open and transparent stakeholder process. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the interruption of any firm Demand. Comments: There are generic concerns with the footnote as amended that must be addressed. The first is the use of the term “Demand”. It is very unclear throughout the footnote whether or not the term Demand includes Interruptible Demand or Demand-Side Management. It is suggested that interruption of Demand be clarified to not include Interruptible Demand or Demand-Side Management to more clearly show the permitted use of that option for load shedding. Further confusion is introduced through the use of the term “firm Demand” in some locations. It is unclear how this is different

than the defined term “Firm Demand” and what the implications of the term “firm Demand” are. The first and third sentences of the first paragraph are unnecessary and should be deleted. However, if they are to be retained, the first sentence is unacceptable in its current state. In some instances, Interruptible Demand or Demand-Side Management are utilized in lieu of transmission additions. These can be considered as acceptable mitigation and there is no justification to minimize their use. Therefore some clarification to the term Demand in the first sentence must be made. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. The second portion of the second bullet should be deleted as it is unncessary: “and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.” If this is to be retained, the very last portion should be deleted “that includes addressing stakeholder comments”. The term “addressing” is unclear. This can be misconstrued to infer that plans must be changed in response to stakeholder comments. This may be inappropriate and may be impossible if conflicting comments are received. It may also create a new standard that all comments must be “addressed”, which may not be a part of the stakeholder process across NERC’s footprint. The first sentence of the paragraph under the two bullets seems to prevent a situation where a combination of re-dispatch and the interruption of Demand are utilized. This restriction could prevent a situation where the use of re-dispatch decreases the amount of Demand which must be interrupted. This footnote should not discourage such adjustments which actually increase the reliability of service to end users. This same sentence also uses the term “shedding of firm Demand”. This should be replaced with “Demand interruption” such that it is consistent with the second bullet; otherwise an unnecessary new term has been introduced. The last sentence of footnote B is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own. This same thought would have to be added to multiple NERC standards if it was added here, otherwise it would infer that such actions are acceptable in all other standards.
Individual
Kathleen Goodman
ISO New England Inc
No
The following comments are provided in regard to this proposal. The first and third sentences of the first paragraph are unnecessary. While we agree with the concept, it is unclear as to how inclusion of these sentences in a standard creates a measureable requirement. There are generic concerns with the footnote as currently proposed. The first is the use of the term “Demand.” It is unclear whether the term Demand includes Interruptible Demand and Demand-Side Management. It is suggested that interruption of Demand be clarified to exclude Interruptible Demand and Demand-Side Management to more clearly show the permitted use of those options. The second concern is that it is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. The third is that not all areas have stakeholder processes. Documenting the use of Demand Interruption should be sufficient without requiring stakeholder review. Therefore the second portion of the second bullet “including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments” is unnecessary and should be deleted. “Addressing stakeholder comments” introduces undefined actions which may be required in response to the comments. For those areas that already have stakeholder processes, stakeholder comments are by definition addressed. As a result, at a minimum “that includes addressing stakeholder comments” should be deleted. Furthermore, for areas that do not have stakeholder processes, so long as they publish their studies impacted parties are aware of the role of demand response. The fourth is that the second paragraph seems to be restricting the use of Demand interruption for the sake of Firm Transfer reduction. This can be stated directly without adding the confusion of re-dispatch. By coupling re-dispatch with a constraint of not shedding Demand, the paragraph also creates confusion as to what to do in a situation where the amount of Demand that is allowed to be shed in the first paragraph could be reduced with re-dispatch. Would re-dispatch not be allowed? We suggest that the paragraph be rewritten as follows: “Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management).” The fifth is if the term ‘firm demand’ survives the proposed changes; is there an intended distinction between the use of the term “firm Demand” and the defined term “Firm Demand”? If these terms are intended to be differently, it is unclear what the term “firm Demand” represents. The final comment is that the last sentence of footnote B is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own. This same thought would have to be added to multiple NERC standards if it was added here, otherwise it would infer that such actions are acceptable in all other standards. If the first and third sentences must be retained the following wording for the footnote is proposed: b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand, (excluding Interruptible Demand or Demand-Side Management), following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Interruptible Demand or Demand-Side Management o Circumstances where the uses of Demand interruption not directly interrupted by the contingency are documented. Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than

Interruptible Demand or Demand Side Management).
Individual
Harold Wyble
Kansas City Power & Light
Yes

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on TPL Table 1 Order — Project 2010-11

The TPL Table 1 Order Drafting Team thanks all commenters who submitted comments on the 3rd posting for Project 2010-11: TPL Table 1 Order. These standards were posted for a 45-day public comment period from November 19, 2010 through January 5, 2011. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 27 sets of comments, including comments from more than 67 different people from approximately 30 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

The SDT reviewed all of the comments received and has made a clarifying change to the structure of the footnote to address industry concerns as to the intent of the SDT. No contextual changes have been made to the footnote. Therefore, the SDT is recommending that this project be moved to a recirculation ballot.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

If you feel that your comment has been overlooked, 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]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, 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, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

Additional Member	Additional Organization	Region	Segment Selection	
1.	Al Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Dean Ellis	Dynegy Generation	NPCC	5
8.	Brian Evans-Mongeon	Utility Services	NPCC	8
9.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
10.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	Chantel Haswell	FPL Group, Inc.	NPCC	5
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Member	Organization	Region	Segment
14.	Michael R. Lombardi	Northeast Utilities	NPCC	1
15.	Randy MacDonald	New Brunswick System Operator	NPCC	2
16.	Bruce Metruck	New York Power Authority	NPCC	6
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

				1	2	3	4	5	6	7	8	9	10
2.	Group	Charles W. Long	SERC Planning Standards Subcommittee	X									X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Pat Huntley	SERC Reliability Corporation	SERC	10
2.	Bob Jones	Southern Company Services	SERC	1
3.	Darrin Church	Tennessee Valley Authority	SERC	1
4.	Jim Kelley	PowerSouth Energy Cooperative	SERC	1
5.	John Sullivan	Ameren Services Company	SERC	1
6.	Phil Kleckley	South Carolina Electric & Gas Co.	SERC	1

				1	2	3	4	5	6	7	8	9	10
3.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
4.	Jason Marshall	Midwest ISO Inc.	MRO	2
5.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
6.	Ken Goldsmith	Alliant Energy	MRO	4
7.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
8.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6

	Group/Individual			
9.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
10.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
11.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
12.	Scott Nickels	Rochester Public Utilties	MRO	4
13.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
14.	Richard Burt	Minnkota Power Cooperative, Inc.	MRO	1, 3, 5, 6

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
4.	Individual	Janet Smith	Arizona Public Service Company	X		X		X	X				
5.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
6.	Individual	Andy Tillery	Southern Company	X		X							
7.	Individual	Aaron Staley	Orlando Utilities Commission	X				X					
8.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
9.	Individual	Si Truc PHAN	Hydro-Quebec TransÃ‰nergie	X									
10.	Individual	Tim Ponseti, VP	TVA Trasnmission Plannning & Compliance	X		X		X				X	
11.	Individual	Alex Rost	New Brunswick System Operator		X								
12.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
13.	Individual	Bernie Pasternack	Transmission Strategies, LLC								X		
14.	Individual	Michael A. Curtis, General Counsel	Mohave Electric Cooperative			X							
15.	Individual	David Thorne	Pepco Holding Inc	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
16.	Individual	John Sullivan	Ameren	X		X		X	X				
17.	Individual	Thad Ness	American Electric Power	X		X		X	X				
18.	Individual	Bob Casey	Georgia Transmission Corporation	X									
19.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
20.	Individual	Saurabh Saksena	National Grid	X		X							
21.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
22.	Individual	Jason L. Marshall	Midwest ISO		X								
23.	Individual	Michael Lombardi	Northeast Utilities	X		X		X					
24.	Individual	Dan Rochester	Independent Electricity System Operator		X								
25.	Individual	Gregory Campoli	New York Independent System Operator		X								
26.	Individual	Kathleen Goodman	ISO New England Inc		X								
27.	Individual	Harold Wyble	Kansas City Power & Light	X		X		X	X				

1. The SDT is proposing a revision to footnote 'b' in the TPL tables to comply with a FERC directive which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Do you agree with the proposed changes and if not, please provide specific reasons for your disagreement.

Summary Consideration: The SDT reviewed all of the comments received and has made a clarifying change to the structure of the footnote to address industry concerns as to the intent of the SDT. No contextual changes have been made to the footnote.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

Comment [llh1]: Same comment as in ballot report – we should replace the actuat "track changes" redline with a formatted version of the same, so that we can clean up the margin line indicating track changes.

Organization	Yes or No	Question 1 Comment
SERC Planning Standards Subcommittee	No	The PSS agrees that the proposed language for footnote b provides some additional clarity. While we generally support the concept, we have concerns that the phrase "is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments" remains ambiguous and should be clarified by limiting stakeholder input to those who have load at risk or local regulators obligated to

Organization	Yes or No	Question 1 Comment
		act on their behalf. Revise the first sentence of the last paragraph to read: "To prepare for a second contingency, curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand."The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Response: The stakeholder process needs to be open and transparent but it is up to the entity to establish the process and whom it may include. No change made. As drafted, footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can only be utilized for a limited time, such as a 2 hour emergency rating. It further clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the firm transfers cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the footnote. No change made.		
Xcel Energy	No	As this is currently drafted, planners would be required to host a forum with stakeholders to discuss hypothetical actions that may be taken in an emergency. We do not see the value in this, nor is it clear who would be considered stakeholders that should attend this forum. For example, we assume it would be the transmission owner's meeting with distribution providers to discuss the possibility of load shedding. Would that be adequate? Xcel Energy is both a Transmission Planner and a Distribution Provider. In this case would the stakeholder be the end user? This should be struck or more clearly defined.
Response: The stakeholder process needs to be open and transparent but it is up to the entity to establish the process and whom it may include. No change made.		
New York Independent System Operator	No	1. Proposed revised footnote language:b) It is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Interruptible Demand or Demand-Side Management o Circumstances where the uses of firm Demand interruption not directly interrupted by the contingency are documented, including alternatives evaluated; and where the firm Demand interruption is subject to review in an open and transparent stakeholder process. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities

Organization	Yes or No	Question 1 Comment
		remain within applicable Facility Ratings and the re-dispatch does not result in the interruption of any firm Demand. 2. Comments:There are generic concerns with the footnote as amended that must be addressed. The first is the use of the term "Demand". It is very unclear throughout the footnote whether or not the term Demand includes Interruptible Demand or Demand-Side Management. It is suggested that interruption of Demand be clarified to not include Interruptible Demand or Demand-Side Management to more clearly show the permitted use of that option for load shedding. 3. Further confusion is introduced through the use of the term "firm Demand" in some locations. It is unclear how this is different than the defined term "Firm Demand" and what the implications of the term "firm Demand" are. 4. The first and third sentences of the first paragraph are unnecessary and should be deleted. However, if they are to be retained, the first sentence is unacceptable in its current state. In some instances, Interruptible Demand or Demand-Side Management are utilized in lieu of transmission additions. These can be considered as acceptable mitigation and there is no justification to minimize their use. Therefore some clarification to the term Demand in the first sentence must be made. 5. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. 6. The second portion of the second bullet should be deleted as it is unncessary: "and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments." If this is to be retained, the very last portion should be deleted "that includes addressing stakeholder comments". The term "addressing" is unclear. This can be misconstrued to infer that plans must be changed in response to stakeholder comments. This may be inappropriate and may be impossible if conflicting comments are received. It may also create a new standard that all comments must be "addressed", which may not be a part of the stakeholder process across NERC's footprint. 7. The first sentence of the paragraph under the two bullets seems to prevent a situation where a combination of re-dispatch and the interruption of Demand are utilized. This restriction could prevent a situation where the use of re-dispatch decreases the amount of Demand which must be interrupted. This footnote should not discourage such adjustments which actually increase the reliability of service to end users. 8. This same sentence also uses the term "shedding of firm Demand". This should be replaced with "Demand interruption" such that it is consistent with the second bullet; otherwise an unnecessary new term has been introduced.

Organization	Yes or No	Question 1 Comment
		9. The last sentence of footnote B is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own. This same thought would have to be added to multiple NERC standards if it was added here, otherwise it would infer that such actions are acceptable in all other standards.

Response: 1. See response to National Grid #1 in ballot comment responses.

2. See response to National Grid #1 in ballot comment responses.

3. See response to National Grid #6 in ballot comment responses.

4. The SDT has reorganized the footnote to clarify its intent and address the issues raised.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

5. See response to National Grid #2 in ballot comment responses.

6. See response to National Grid #4 in ballot comment responses.

7. The SDT has reorganized the footnote to clarify its intent and address the issues raised.

8. The SDT has reorganized the footnote to clarify its intent and address the issues raised.

Comment [llh2]: Same comment as in the ballot comment report – I think we should replace the "track changes" redlining with font changes that indicate the same, to clean up document for stakeholders.

Organization	Yes or No	Question 1 Comment
9. See response to National Grid #7 in ballot comment responses.		
ISO New England Inc	No	1. The following comments are provided in regard to this proposal. The first and third sentences of the first paragraph are unnecessary. While we agree with the concept, it is unclear as to how inclusion of these sentences in a standard creates a measureable requirement. 2. There are generic concerns with the footnote as currently proposed. The first is the use of the term “Demand.” It is unclear whether the term Demand includes Interruptible Demand and Demand-Side Management. It is suggested that interruption of Demand be clarified to exclude Interruptible Demand and Demand-Side Management to more clearly show the permitted use of those options. 3. The second concern is that it is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. 4. The third is that not all areas have stakeholder processes. Documenting the use of Demand Interruption should be sufficient without requiring stakeholder review. Therefore the second portion of the second bullet “including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments” is unnecessary and should be deleted. “Addressing stakeholder comments” introduces undefined actions which may be required in response to the comments. For those areas that already have stakeholder processes, stakeholder comments are by definition addressed. As a result, at a minimum “that includes addressing stakeholder comments” should be deleted. Furthermore, for areas that do not have stakeholder processes, so long as they publish their studies impacted parties are aware of the role of demand response. 5. The fourth is that the second paragraph seems to be restricting the use of Demand interruption for the sake of Firm Transfer reduction. This can be stated directly without adding the confusion of re-dispatch. By coupling re-dispatch with a constraint of not shedding Demand, the paragraph also creates confusion as to what to do in a situation where the amount of Demand that is allowed to be shed in the first paragraph could be reduced with re-dispatch. Would re-dispatch not be allowed? We suggest that the paragraph be rewritten as follows: “Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management).” 6. The fifth is if the term ‘firm demand’ survives the proposed changes; is there an intended distinction between the use of the term “firm Demand” and the defined term “Firm Demand”? If these terms are intended to be differently, it is unclear what the term “firm Demand” represents. 7. The final comment is that the last sentence of footnote B is unnecessary and should be deleted. It is

Organization	Yes or No	Question 1 Comment
		never acceptable to cause reliability concerns in another area while addressing your own. This same thought would have to be added to multiple NERC standards if it was added here, otherwise it would infer that such actions are acceptable in all other standards. 8. If the first and third sentences must be retained the following wording for the footnote is proposed:b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand, (excluding Interruptible Demand or Demand-Side Management), following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Interruptible Demand or Demand-Side Management o Circumstances where the uses of Demand interruption not directly interrupted by the contingency are documented. Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management).

Response: 1. The SDT believes that the first part of the footnote is necessary to provide context for the items that follow and has crafted the language to provide a balance between flexibility and consistency across NERC. No change made.

2. See ballot response to NPCC #1.

3. See ballot response to NPCC #2.

4. The SDT believes that in situations where an entity's planning studies require the interruption of firm load to remain within BES Facility ratings that the entity needs to share those plans in an open and transparent stakeholder process to ensure that other parties that may be adversely impacted by those decisions have the ability to review and comment on those plans. No change made.

5. See ballot response to NPCC #5.

6. The SDT has corrected the indicated errors.

7. See ballot response to NPCC #6.

8. The SDT has reorganized the text in the footnote to address this concern.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited

Organization	Yes or No	Question 1 Comment
circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~ ~~Interruptible Demand or Demand-Side Management~~ ~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~		
Northeast Power Coordinating Council	No	There is concern with the use of the term Demand. It is unclear throughout the footnote whether or not the term Demand includes Interruptible Demand or Demand-Side Management. It is suggested that interruption of Demand be clarified to not include Interruptible Demand or Demand-Side Management to more clearly show the permitted use of Load shedding. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. Language that mitigation of Load and/or Demand interruption should be pursued within the planning process should be reinstated as reinforcement of a Transmission Providers' planning obligations to their load customers, and system operations. Footnote 'b' should be made to read as follows:b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of Load and/or Demand following Contingency events. Interruption of Load and/or Demand is discouraged and all measures to mitigate such interruption should be pursued within the planning process. However, it is recognized that Load and/or Demand will be interrupted if it is directly served by the elements automatically removed from service by the Protection System as a result of a Contingency. Furthermore, in extraordinary circumstances within the planning process Load and/or Demand may need to be interrupted to address BES performance requirements. When interruption of Load and/or Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Circumstances where the use of Load and/or Demand interruption are documented, including alternatives evaluated; and where the Load and/or Demand interruption is made available for review in an open and transparent stakeholder process.If Load and/or Demand interruption is necessary, planning should indicate the amount needed, and not specify how it would be obtained. What Load and/or Demand is

Organization	Yes or No	Question 1 Comment
		interrupted is an operational decision. Additional comments not included in the material listed for footnote ‘b’ on the Comment Form. In the paragraph below the bullets in footnote ‘b’, confusion is introduced through the use of the term “firm Demand”. It is unclear how this is different than the defined term “Firm Demand” and what the implications of the term “firm Demand” are. This footnote should not discourage such adjustments which actually increase the reliability of service to end users. The last sentence of footnote ‘b’ is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own.
Response: This comment is identical to the one made by NPCC in the ballot and the SDT has answered the comment in that forum.		
Arizona Public Service Company	No	It is not clear whether both bullets under "footnote b" have to be met or only one of the two have to be met. It is suggested that the standard be very clear about this.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Southern Company	No	Southern Company is voting "no" on the footnote b ballot because of concerns that the reliability of firm transfers could be compromised. The existing Table I Transmission System Standards, which have been in place as early as the 1997 NERC Planning Standards, do not allow Loss of Demand or Curtailed Firm Transfers under single (Category B) contingencies. Footnote B addressed two areas: 1) the loss of radial or local network load, which Southern Company agrees that the drafting team has appropriately clarified and 2) preparing for the next contingency, which Southern Company does not agree has been appropriately clarified.Southern Company believes the proposed wording "Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch" now allows for the curtailment of firm transfers for single contingencies, whereas Southern Company did not believe this was previously permitted under the standards. Southern Company interprets the new language to allow a planner to curtail firm transfers (generation) to address a single contingency. Southern Company interpreted the original language to not permit the curtailment of firm transfers (generation) for a single contingency, but rather that a planner would develop a suitable transmission reinforcement or other mitigation. Southern Company is concerned that the proposed language could result in a degradation in the dependability of firm transfers impacting the reliability of those customers who rely upon them. Southern Company agrees that a system reconfiguration including the redispatch of generation is appropriate when preparing for a second contingency (Category C).Therfore, a distinction is needed between what is allowed in response to a first contingency and what is allowed to be prepared for a second contingency. The curtailment of firm transfers should not be allowed as a response to the first contingency. This practice would undermine the concept of firm transfers. The curtailment of firm transfers should only be allowed in footnote b as a system adjustment to be prepared for a second contingency. We propose the following to clarify that curtailments are permitted only to prepare

Organization	Yes or No	Question 1 Comment
		for the second contingency. "To prepare for the next contingency, curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch".
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Orlando Utilities Commission	No	The current language provides a balance between the end goal of reliablity (no load loss for B events) and the practical constraint that project cost may outweigh the benefit. Two things are unclear though. Item one: The standard team should clarify if the bullets under note B are intended to be an AND (both conditions met) or an OR (either condition met). As currently written it is not clear. Item #2: The section under firm transfers is in conflict with the section above. If Demand is being curtailed under the first or second bullet and it's served by firm service then service should also be curtailed, however as written any demand served by firm service could not be curtailed.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Duke Energy	Yes	The effective date in the Implementation Plan needs to be changed to match the Effective Date in the standards, in order to clarify the allowed interruption of Non-consequential load before the new Footnote 'b' takes effect.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Hydro-Quebec Transenergie	Yes	Paragraph should be more clear as:b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances within the planning process, Demand may need to be interrupted to address BES performance requirements. In such case : o Only Interruptible Demand or Demand-Side Management are allowed;o Circumstances where the uses of Demand interruption is needed shall be documented, compared to alternatives, and reviewed in an open and transparent stakeholder process that address stakeholder comments. Curtailment of firm transfers is allowed, when coupled with the appropriate and necessary re-dispatch of resources where it can be demonstrated that this does not result in the shedding of any firm Demand and that Facilities remain within applicable Facility Ratings, including Facilities external to the Transmission Planner's planning region when they are relied upon.
Response: The SDT believes that the changes indicated in your proposed footnote do not add any additional clarity. However, the SDT has reorganized the footnote to clarify its intent.		

Organization	Yes or No	Question 1 Comment
b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~ ~~Interruptible Demand or Demand-Side Management~~ ~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~		
TVA Trasnmission Plannning & Compliance	No	TVA appreciates the SDT's efforts to clarify and improve this complex and challenging area. However, as mentioned in our last comments regarding footnote b, TVA still believes that the SDT's proposal is still focusing more on reliability of local loads than on the overall reliability of the BES. Reliability of local loads should be addressed outside the TPL standards and therefore should not be used/referenced in footnote b. Existing stakeholder processes (referred to in the SDT proposal) typically focus on larger system issues and not on local load serving. TVA believes that some local load should be allowed to be dropped in order to maintain BES reliability. Instead of the proposed footnote b, TVA suggests that the SDT define a "local area" with guidelines detailing the reliability requirements for these local area loads. This would separate the local area load requirements from the BES requirements in the TPL standards.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
New Brunswick System Operator	No	NBSO agrees with the principles of the current version of the proposed footnote, as far as NBSO's interpretation of the footnote is correct. NBSO has the following detailed comments:1. The first paragraph contains many general statements that attempts to capture essential planning principles. NBSO feels that such language is not suited for a footnote. NBSO suggests re-wording of the first paragraph to state:Interruption of Demand may be utilized within the planning process to address BES performance requirements. Such cases are limited to:NBSO also suggests turning the phrase that addresses Demand lost that was served by elements removed from service as a result of a Contingency into a bullet item. NBSO feels

Organization	Yes or No	Question 1 Comment
		that this adds clarity since all of the acceptable instances of Demand interruption are now listed as bulleted items.2. NBSO interprets that the currently proposed footnote allows for the two bulleted options to be used exclusively or in combination. Thus for clarification NBSO suggests adding “or” after each bulleted item, with the exclusion of the final bulleted item.3. NBSO suggests removing the last sentence of the last paragraph. Likely all industry members understand that causing reliability concerns in other areas is never acceptable. This principle is not limited to the standard in question, and thus such a statement could require the update of other standards.4. NBSO interprets that the use of the word “Demand” in the second bullet of the proposed footnote is referring to use of Firm Demand since the first bullet covers the other types of Demand (Demand = Firm Demand + Interruptible Demand). As such NBSO suggests replacing “Demand” with “Firm Demand” in the second bullet.5. NBSO feels that the statement “that includes addressing stakeholder comments” should be removed from the last phrase of the second bullet. An open and transparent stakeholder process should adequately address stakeholder comments and concerns. Explicitly specifying that all stakeholder comments be addressed may add undue burden if the word “address” is misconstrued. The task of addressing stakeholder comments is more appropriately addressed and defined in each area’s respective process.6. NBSO suggests replacing the word “shedding” with “interruption” in the last phrase of the last paragraph to remain consistent with the rest of the proposed footnote. NBSO also suggests capitalizing “firm” in the term “Firm Demand” to remain consistent with the NERC glossary of terms.7. There is no term “transfers” in the NERC glossary of terms. Perhaps some other defined term from the glossary could be used in lieu of “transfers” (e.g. Firm Transmission Service).Taking into account the NBSO comments, the footnote could read as follows:b) Interruption of Demand may be utilized within the planning process to address BES performance requirements. Such cases are limited to:-Demand directly served by Elements removed from service as a result of a Contingency, or-Use of Interruptible Demand or Demand-Side Management, or-Interruption of Firm Demand when acceptable circumstances for such interruptions are documented (including alternatives evaluated), and where the Firm Demand interruption is subject to review in an open and transparent stakeholder process.Curtailment of Firm Transmission Service is allowed when coupled with the appropriate re-dispatch of resources obligated to do so, and it can be demonstrated that Facilities remain within applicable Facility Ratings and there is no additional interruption of Firm Demand.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Manitoba Hydro	No	The last bullet should be made clearer by adding the words “in jurisdictions” before the word “where”. Not all jurisdictions are mandated to have a stakeholder process, so the standard should be clearly written to recognize this situation. "Circumstances where the use of Demand interruption are documented, including alternatives evaluated; and IN JURISDICTIONS where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments."

Organization	Yes or No	Question 1 Comment
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Ameren	No	We agree with the statement that an objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following single contingency events. While we appreciate the drafting team's efforts in removing the need for acceptance by other parties in the stakeholder process, we still feel that language in the second bullet of the revised footnote b should be modified to remove all references to an open and transparent stakeholder process. Existing RTO stakeholder processes that we are aware of focus on larger system issues, rather than on local load serving issues. Therefore, we believe that the load serving issues following single contingency events are issues between the customer and the utility, and should be addressed in one-on-one forums between those entities.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
National Grid	No	National Grid supports the direction the drafting team has taken. However, it has a few concerns with the language of the footnote as amended. 1. Use of the term "Demand": In the first sentence, it is unclear whether the term Demand includes Interruptible Demand and Demand-Side Management. It is suggested that interruption of Demand be clarified to exclude Interruptible Demand or Demand-Side Management. 2. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. 3. National Grid also suggests changing "Demand interruption" to "interruption of Demand" in second bullet under "b)" to avoid awkward and incorrect phasing.4. 'Addressing stakeholder comments' introduces undefined actions which may be required in response to the comments. If 'Demand interruption is subject to review in an open and transparent stakeholder process', then stakeholder comments will be addressed without creating an undefined commitment to require it. As a result, "that includes addressing stakeholder comments" should be deleted. 5. The second paragraph seems to be restricting the use of Demand interruption for the sake of Firm Transfer reduction. This can be stated directly without adding the confusion of re-dispatch. By coupling re-dispatch with a constraint of not shedding Demand, the paragraph also creates confusion as to what to do in a situation where the amount of Demand that is allowed to be shed in the first paragraph could be reduced with re-dispatch. Would re-dispatch not be allowed? National Grid suggests that the paragraph be rewritten as follows: 'Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management).' 6. National Grid seeks clarification if there is an intended distinction between the use of the term "firm Demand" and the defined term "Firm Demand" or is that just a typo?7. The last sentence of footnote B is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own. This same thought would have to be added to multiple

Organization	Yes or No	Question 1 Comment
		NERC standards if it were added here, otherwise it would infer that such actions are acceptable in all other standards.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Northeast Utilities	No	The revised language of Footnote b suggests that non-consequential demand interruption (load that is not directly served by the elements removed from service as a result of the contingency) could be used to mitigate reliability concerns arising from NERC Category B contingency events (i.e., single element contingencies). This language seems to encourage operational workarounds and adds burdens for operators of the system. NU believes this is not consistent with planning a highly reliable bulk electric system and thus does not support this weaker language.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Kansas City Power & Light	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
PacifiCorp	Yes	appreciates the efforts of the SDT and supports revision of TLP-002-0 Table 1 footnote “b” as stated in this draft.
Transmission Strategies, LLC	Yes	
Mohave Electric Cooperative	Yes	
Pepco Holding Inc	Yes	
American Electric Power	Yes	
Georgia Transmission Corporation	Yes	
American Transmission Company	Yes	

Organization	Yes or No	Question 1 Comment
Midwest ISO	Yes	
Independent Electricity System Operator	Yes	
Response: Thank you for your support.		

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Ballot Pool Open November 19 – December 22, 2010
Comment Period Open November 19 – January 5, 2011

Now available at: http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

TPL Table 1, Footnote B SAR (Project 2010-11)

The TPL Table 1 Order Drafting Team is seeking comments on Table 1 footnote 'b' in TPL-001-1 through TPL-004-1 until **8 p.m. EDT on January 5, 2011.**

FERC's Order in docket RM06-16-009 requires the ERO to clarify TPL-002-0, Table 1- footnote 'b,' regarding the planned or controlled interruption of electric supply, where a single contingency occurs on a transmission system, and originally directed NERC to file the revised standards by June 30, 2010. To meet this directive, a proposed revision was posted for "Urgent Action" and balloted from May 17-27, 2010. The proposed revision achieved a quorum (84%) and almost enough affirmative votes (64%) to achieve weighted segment approval; however, many balloters provided comments indicating the need for additional modifications. Following the initial ballot, FERC extended the due date to March 31, 2011; thus the project is no longer considered "Urgent Action."

Because Table 1 appears in TPL-001, TPL-002, TPL-003, and TPL-004, the change is reflected in all four standards:

- TPL-001-1 - System Performance Under Normal (No Contingency) Conditions (Category A)
- TPL-002-1b - System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- TPL-003-1a - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
- TPL-004-1 - System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

Ballot Pool (through December 22, 2010)

Because of the length of time between the last ballot (May 2010) and the time of the upcoming ballot (December 2010, many members of the initial ballot pool are no longer in the Registered Ballot Body. The existing ballot pool has been dissolved and a **new ballot pool** is being formed to vote on the proposed revision to Table 1, footnote 'b.' Registered Ballot Body members may join this new ballot pool to be eligible to vote on these proposed modifications **until 8 a.m. EDT on December 22, 2010**.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2010-11_TPL_Table_1_in

Comment Period (through January 5, 2011)
Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page:

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Next Steps
An initial ballot will be conducted during the last 10 days of the formal comment period. The drafting team will consider all comments (those submitted with a comment form, and those submitted with a ballot) and will determine whether to make additional changes to the standards. The team will post its response to comments and, if the standards have only minor changes, will post the standards and conduct a 10-day recirculation ballot.

Standards Process
The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Initial Ballot Open December 27, 2010 – January 5, 2011

Now available at: : https://standards.nerc.net/CurrentBallots.aspx

TPL Table 1, Footnote B SAR (Project 2010-11)

An initial ballot is open on Table 1 footnote 'b' in TPL-001-1 through TPL-004-1 until **8 p.m. EDT on January 5, 2011.**

FERC's Order in docket RM06-16-009 requires the ERO to clarify TPL-002-0, Table 1- footnote 'b,' regarding the planned or controlled interruption of electric supply, where a single contingency occurs on a transmission system, and originally directed NERC to file the revised standards by June 30, 2010. To meet this directive, a proposed revision was posted for "Urgent Action" and balloted from May 17-27, 2010. The proposed revision achieved a quorum (84%) and almost enough affirmative votes (64%) to achieve weighted segment approval; however, many balloters provided comments indicating the need for additional modifications. Following the initial ballot, FERC extended the due date to March 31, 2011; thus the project is no longer considered "Urgent Action."

Because Table 1 appears in TPL-001, TPL-002, TPL-003, and TPL-004, the change is reflected in all four standards:

- TPL-001-1 - System Performance Under Normal (No Contingency) Conditions (Category A)
- TPL-002-1b - System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- TPL-003-1a - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
- TPL-004-1 - System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

Comment Period (through January 5, 2011)

A formal, 45-day comment period began on November 19, 2010 and will conclude when the ballot closes on January 5, 2011. Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page:

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Next Steps

The drafting team will consider all comments (those submitted with a comment form, and those submitted with a ballot) and will determine whether to make additional changes to the standards. The team will post its response to comments and, if the standards have only minor changes, will post the standards and conduct a 10-day recirculation ballot.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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Princeton, NJ 08540
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Ballot Results	
Ballot Name:	Project 2010-11 TPL Table 1 Footnote B SAR_in
Ballot Period:	12/27/2010 - 1/5/2011
Ballot Type:	Initial
Total # Votes:	283
Total Ballot Pool:	313
Quorum:	**90.42 % The Quorum has been reached**
Weighted Segment Vote:	83.33 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			# Votes	Fraction	# Votes	Fraction	# Votes	
1 - Segment 1.	95	1	64	0.8	16	0.2	6	9
2 - Segment 2.	11	1	5	0.5	5	0.5	1	0
3 - Segment 3.	66	1	46	0.793	12	0.207	5	3
4 - Segment 4.	26	1	17	0.944	1	0.056	6	2
5 - Segment 5.	58	1	40	0.851	7	0.149	4	7
6 - Segment 6.	37	1	25	0.862	4	0.138	3	5
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.5	5	0.5	0	0	1	2
9 - Segment 9.	4	0.4	4	0.4	0	0	0	0
10 - Segment 10.	8	0.6	6	0.6	0	0	0	2
Totals	**313**	**7.5**	**212**	**6.25**	**45**	**1.25**	**26**	**30**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Jason Shaver		
1	APS	Barbara McMinn	Affirmative	
1	Arizona Public Service Co.	Robert D Smith	Negative	View
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Abstain	

1	Avista Corp.	Scott Kinney	Affirmative	View
1	BC Transmission Corporation	Gordon Rawlings	Negative	View
1	Beaches Energy Services	Joseph S. Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	CenterPoint Energy	Paul Rocha	Abstain	
1	Central Maine Power Company	Kevin L Howes	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	View
1	City of Vero Beach	Randall McCamish		
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	View
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker	Affirmative	View
1	Dominion Virginia Power	John K Loftis	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils		
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	GDS Associates, Inc.	Claudiu Cadar	Negative	View
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	View
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stan T. Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Lone Star Transmission, LLC	Julius Horvath	Affirmative	View
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	View
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	National Grid	Saurabh Saksena	Negative	View
1	Nebraska Public Power District	Richard L. Koch	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Negative	View
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Utilities	David H. Boguslawski	Negative	View
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Douglas G Peterchuck	Affirmative	
1	Oncor Electric Delivery	Michael T. Quinn	Abstain	
1	Orlando Utilities Commission	Brad Chase	Negative	View
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	View
1	PacifiCorp	Colt Norrish	Affirmative	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	

1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Linda Brown	Negative	View
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Texas Electric Cooperative	Richard McLeon	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Negative	View
1	Southern Illinois Power Coop.	William G. Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	View
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young	Affirmative	View
1	Tennessee Valley Authority	Larry Akens	Negative	View
1	Tri-State G & T Association, Inc.	Keith V. Carman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Negative	View
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	View
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	Alberta Electric System Operator	Mark B Thompson	Abstain	View
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	View
2	California ISO	Gregory Van Pelt	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Negative	View
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Jason L Marshall	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Negative	View
2	New York Independent System Operator	Gregory Campoli	Affirmative	View
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Negative	View
3	Alabama Power Company	Richard J. Mandes	Negative	View
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Negative	View
3	Arkansas Electric Cooperative Corporation	Philip Huff	Abstain	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	Avista Corp.	Robert Lafferty	Affirmative	View
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	View
3	Black Hills Power	Andy Butcher	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	View
3	City of Leesburg	Phil Janik	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	View
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	Entergy	Joel T Plessinger	Abstain	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Negative	View
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Hydro One Networks, Inc.	David L Kiguel	Affirmative	View
3	JEA	Garry Baker	Affirmative	

3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory David Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Negative	View
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	View
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Negative	View
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Negative	View
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	PacifiCorp	John Apperson	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	South Carolina Electric & Gas Co.	Hubert C. Young	Affirmative	
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	View
3	Tampa Electric Co.	Ronald L Donahey	Affirmative	View
3	Tennessee Valley Authority	Ian S Grant	Negative	View
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power - Ohio	Kevin Koloini	Abstain	
4	American Public Power Association	Allen Mosher	Affirmative	
4	Arkansas Electric Cooperative Corporation	Ronnie Frizzell	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Abstain	
4	City of Clewiston	Kevin McCarthy	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas W. Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	LaGen	Richard Comeaux		
4	Modesto Irrigation District	Spencer Tacke	Negative	View
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Oklahoma Municipal Power Authority	Terri Pyle	Abstain	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	View
4	Tallahassee Electric	Allan Morales	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5		Edwin B Cano	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	APS	Mel Jensen	Negative	View
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		

5	Black Hills Corp	George Tatar	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	View
5	City of Tallahassee	Alan Gale	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	View
5	Consumers Energy	James B Lewis	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Electric Power Supply Association	Jack Cashin		
5	Energy Northwest - Columbia Generating Station	Doug Ramey	Affirmative	
5	Entergy Corporation	Stanley M Jaskot		
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	View
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	JEA	Donald Gilbert	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	Thomas J Trickey		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	View
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	View
5	New York Power Authority	Gerald Mannarino		
5	Northern California Power Agency	Tracy R Bibb	Abstain	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Pete Ungerman	Affirmative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	Jerzy A Slusarz	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	View
5	Tenaska, Inc.	Scott M. Helyer	Negative	
5	Tennessee Valley Authority	George T. Ballew	Negative	View
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	View
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Abstain	
5	Xcel Energy, Inc.	Liam Noailles	Abstain	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	View
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	View
6	City of Austin dba Austin Energy	Lisa L Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	View
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit		
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View

6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas E Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	View
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	View
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	View
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Abstain	
8		Roger C Zaklukiewicz		
8		James A Maenner	Affirmative	
8		Edward C Stein	Affirmative	
8	INTELLIBIND	Kevin Conway		
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Transmission Strategies, LLC	Bernie M Pasternack	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	View
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	Oregon Public Utility Commission	Jerome Murray	Affirmative	
9	Snohomish County PUD No. 1	William Moojen	Affirmative	
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	View
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B Edge		
10	Southwest Power Pool Regional Entity	Stacy Dochoda		
10	Texas Reliability Entity	Larry D. Grimm	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	View

Standards Announcement

Initial Ballot Results

Project 2010-11: TPL Table 1, Footnote B

Now available at: https://standards.nerc.net/Ballots.aspx

An initial ballot of Table 1 footnote 'b' in TPL-001-1 through TPL-004-1 ended on January 5, 2011. Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 90.42%
Approval: 83.33%

Background:
FERC Order RM06-16-009 requires the ERO to clarify TPL-002-0, Table 1 - footnote 'b,' regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system and originally directed NERC to file the revised standards by June 30, 2010. To meet this directive a proposed revision was posted for "Urgent Action" and balloted from May 17-27, 2010. The proposed revision achieved a quorum (84%) and almost enough affirmative votes (64%) to achieve weighted segment approval; however, many balloters provided comments indicating the need for additional modifications. Following the initial ballot, FERC extended the due date to March 31, 2011; thus the project is no longer considered "Urgent Action."

Because Table 1 appears in TPL-001, TPL-002, TPL-003, and TPL-004, the change is reflected in all four standards:

- TPL-001-1 - System Performance Under Normal (No Contingency) Conditions (Category A)
- TPL-002-1b - System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- TPL-003-1a - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
- TPL-004-1 - System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

More details may be found on the project page:
http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Next Steps
The drafting team will consider all comments (those submitted with a comment form and those submitted with a ballot) and will determine whether to make additional changes to the footnote in the four standards. The team

will post its response to comments and, if the footnote has only minor changes, will post the standards and conduct a 10-day recirculation ballot.

Ballot Criteria

Approval requires both (1) a quorum, which is established by at least 75% of the members of the ballot pool submitting either an affirmative vote, a negative vote, or an abstention, and (2) a two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and non-responses.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

North American Electric Reliability Corporation
116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com

Consideration of Comments on Successive Ballot — Project 2010-11 – TPL Table 1, Footnote b

Successive Ballot Dates: **12/27/2010 - 1/5/2011**

Summary Consideration:

The SDT reviewed all of the comments received and has made a clarifying change to the structure of the footnote to address industry concerns as to the intent of the SDT. No contextual changes have been made to the footnote. Therefore, the SDT is recommending that this project be moved to a recirculation ballot.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

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]

Balloter	Company	Seg-ment	Vote	Comment
Richard J. Mandes	Alabama Power Company	3	Negative	Southern Company is voting "no" on the footnote b ballot because of concerns that the reliability of firm transfers could be compromised. The existing Table I Transmission System Standards,

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

Balloter	Company	Seg-ment	Vote	Comment
Anthony L Wilson	Georgia Power Company	3	Negative	which have been in place as early as the 1997 NERC Planning Standards, do not allow Loss of Demand or Curtailed Firm Transfers under single (Category B) contingencies. Footnote B addressed two areas: 1) the loss of radial or local network load, which Southern Company agrees that the drafting team has appropriately clarified and 2) preparing for the next contingency, which Southern Company does not agree has been appropriately clarified. Southern Company believes the proposed wording "Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch" now allows for the curtailment of firm transfers for single contingencies, whereas Southern Company did not believe this was previously permitted under the standards. Southern Company interprets the new language to allow a planner to curtail firm transfers (generation) to address a single contingency. Southern Company interpreted the original language to not permit the curtailment of firm transfers (generation) for a single contingency, but rather that a planner would develop a suitable transmission reinforcement or other mitigation. Southern Company is concerned that the proposed language could result in a degradation in the dependability of firm transfers impacting the reliability of those customers who rely upon them. Southern Company agrees that a system reconfiguration including the redispatch of generation is appropriate when preparing for a second contingency (Category C). Therfore, a distinction is needed between what is allowed in response to a first contingency and what is allowed to be prepared for a second contingency. The curtailment of firm transfers should not be allowed as a response to the first contingency. This practice would undermine the concept of firm transfers. The curtailment of firm transfers should only be allowed in footnote b as a system adjustment to be prepared for a second contingency. We propose the following to clarify that curtailments are permitted only to prepare for the second contingency. "To prepare for the next contingency, curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch".
Don Horsley	Mississippi Power	3	Negative	
Horace Stephen Williamson	Southern Company Services, Inc.	1	Negative	

Response: The SDT has changed the wording 'coupled with' to 'achieved through' to better clarify the SDT's intent.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~-C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand

Balloter	Company	Seg-ment	Vote	Comment
interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~ As drafted, footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can only be utilized for a limited time, such as a 2 hour emergency rating. It further clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the firm transfers cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the footnote. No change made.				
Jennifer Richardson	Ameren Energy Marketing Co.	6	Negative	We agree with the statement that an objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following single contingency events. While we appreciate the drafting team's efforts in removing the need for acceptance by other parties in the stakeholder process, we still feel that language in the second bullet of the revised footnote b should be modified to remove all references to an open and transparent stakeholder process. Existing RTO stakeholder processes that we are aware of focus on larger system issues, rather than on local load serving issues. Therefore, we believe that the load serving issues following single contingency events are issues between the customer and the utility, and should be addressed in one-on-one forums between those entities.
Kirit S. Shah	Ameren Services	1	Negative	
Response: The SDT disagrees that this should be handled through two party interactions. The SDT believes that in situations where an entity's planning studies require the interruption of Firm Demand to remain within BES Facility Ratings that the entity needs to share those plans in an open and transparent stakeholder process to ensure that other parties that may be impacted by those decisions have the ability to review those plans. No change made.				
Steven Norris	APS	3	Negative	It is not clear whether both bullets under "footnote b" have to be met or only one of the two have to be met. It is suggested that the standard be very clear about this
Mel Jensen	APS	5	Negative	
Robert D Smith	Arizona Public Service Co.	1	Negative	
Response: The bullets – o Interruptible Demand or Demand-Side Management and o Circumstances where … are not requirements that must be met, but rather they define the conditions, either one or both, where Load is allowed to be interrupted. The SDT has rearranged the footnote to clarify the intent of the footnote. **b)** An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch,				

<table>
<thead>
<tr><th>Balloter</th><th>Company</th><th>Seg-ment</th><th>Vote</th><th>Comment</th></tr>
</thead>
<tbody>
<tr><td colspan="5">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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~</td></tr>
<tr><td>John Tolo</td><td>Tucson Electric Power Co.</td><td>1</td><td>Negative</td><td>The first sentence of the second paragraph appears to conflict with the first paragraph in that it indicates that curtailment of transfers is allowed under certain conditions as long as it doesn't result in the shedding of any firm Demand. Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.</td></tr>
<tr><td>Scott Kinney</td><td>Avista Corp.</td><td>1</td><td>Affirmative</td><td rowspan="2">The first sentence of the second paragraph appears to conflict with the first paragraph in that it indicates that curtailment of transfers is allowed under certain conditions as long as it doesn't result in the shedding of any firm Demand. Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.</td></tr>
<tr><td>Robert Lafferty</td><td>Avista Corp.</td><td>3</td><td>Affirmative</td></tr>
<tr><td>Brenda S. Anderson</td><td>Bonneville Power Administration</td><td>6</td><td>Affirmative</td><td>Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.</td></tr>
<tr><td>William Mitchell Chamberlain</td><td>California Energy Commission</td><td>9</td><td>Affirmative</td><td>I am voting for this improved standard but I am concerned that the first sentence of the second paragraph appears to conflict with the first paragraph in that it indicates that curtailment of transfers is allowed under certain conditions as long as it doesn't result in the shedding of any firm Demand. This problem could be corrected by adding language to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.</td></tr>
</tbody>
</table>

Balloter	Company	Seg-ment	Vote	Comment
Chang G Choi	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	1	Affirmative	Tacoma Power agrees that the revision is better than the existing language. However, to improve clarity on the interrelationship of the 2 paragraphs of Footnote B, we strongly suggest adding the following phrase to the end of the first sentence of the second paragraph, “unless the firm Demand is allowed to be shed pursuant to the above paragraph in this footnote."
Max Emrick	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	5	Affirmative	
James Tucker	Deseret Power	1	Affirmative	As drafted the first paragraph of proposed Footnote B identifies the objective of minimizing interruption of Demand following Contingencies and goes on to identify the limited situation where interruption of demand may be necessary. However, the first sentence of the second paragraph appears to conflict with the first paragraph in that it indicates that curtailment of transfers is allowed under certain conditions as long as it doesn’t result in the shedding of any firm Demand. Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed
Chifong L. Thomas	Pacific Gas and Electric Company	1	Affirmative	PG&E supports the proposed footnote B. We believe, however, there is a potential for confusion with the language as currently drafted. As drafted the first paragraph of proposed Footnote B identifies the limited situations where interruption of demand may be necessary and would be allowed. However, the first sentence of the second paragraph indicates that curtailment of transfers is allowed under certain conditions as long as it doesn’t result in the shedding of any firm Demand. Taken together with the first paragraph, this requirement can be confusing because the first paragraph potentially conflicts with the second paragraph. Please change the first sentence in the second paragraph to read, "Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand, the interruption of which is otherwise allowed as described above.”
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Affirmative	Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.
Travis Metcalfe	Tacoma Public Utilities	3	Affirmative	Tacoma Power agrees that the revision is better than the existing language. However, to improve clarity on the interrelationship of the 2 paragraphs of Footnote B, we strongly suggest adding the following phrase to the end of the first sentence of the second paragraph, “unless the firm Demand is allowed to be shed pursuant to the above paragraph in this footnote.”

Balloter	Company	Seg-ment	Vote	Comment
Keith Morisette	Tacoma Public Utilities	4	Affirmative	
Michael C Hill	Tacoma Public Utilities	6	Affirmative	
Beth Young	Tampa Electric Co.	1	Affirmative	Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed
Ronald L Donahey	Tampa Electric Co.	3	Affirmative	
RJames Rocha	Tampa Electric Co.	5	Affirmative	Recommend adding language to paragraph 2, sentence 1 to clarify shedding of firm demand is allowed as stated in Paragraph 1.
Benjamin F Smith II	Tampa Electric Co.	6	Affirmative	
Melissa Kurtz	U.S. Army Corps of Engineers	5	Affirmative	Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.
Brandy A Dunn	Western Area Power Administration	1	Affirmative	As drafted, the first paragraph of proposed Footnote B identifies the objective of minimizing interruption of Demand following Contingencies and goes on to identify the limited situation where interruption of demand may be necessary. However, the first sentence of the second paragraph appears to conflict with the first paragraph in that it indicates that curtailment of transfers is allowed under certain conditions as long as it doesn't result in the shedding of any firm Demand. Western recommends that the Drafting Team include language at the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.

Balloter	Company	Seg-ment	Vote	Comment
Louise McCarren	Western Electricity Coordinating Council	10	Affirmative	WECC supports the concept that is clarified in the proposed language for Footnote B. We have noted however, what could potentially be confusing language between paragraphs one and two of the proposed language. Paragraph one correctly indicates that one of the objectives of transmission planning is to minimize the likelihood and magnitude of interruption of Demand. The first paragraph also recognizes that while this is an objective, there may be certain limited conditions where Demand is interrupted. In recognizing this, the first paragraph lists those limited instances when Demand may be interrupted. However, the first sentence of paragraph two could be interpreted to mean that shedding of Firm Demand is not allowed. The sentence means that shedding of Firm Demand is not allowed due to curtailment of firm transfers, but if there is a situation where curtailment of firm transfers is necessary and curtailment of Demand per the reasons listed in the first paragraph occurs, it should be clear that this is allowed. Suggest adding the following language, or something similar, to the end of the first sentence of the second paragraph of Footnote B. ...except as allowed above.

Response: The SDT has reorganized the footnote to clarify intent and address the issue raised.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

Balloter	Company	Seg-ment	Vote	Comment
Venkataramakrishnan Vinnakota	BC Hydro	2	Negative	Footnote "b" of TPL-001/2/3/4 is still vague and not acceptable. The last paragraph of Footnote b now reads: "Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected." We would like the SDT to answer the following questions related to the paragraph quoted above: 1) What is meant by "firm transfers"? Is it simply energy flowing in real-time on Firm Transmission Service (NERC defined term) that was not previously curtailed in the hour-ahead or day-ahead scheduling processes, or does it refer to ALL Firm Transmission Service that was sold on a path? 2) Please provide an example of what an "appropriate re-dispatch of resources obligated to re-dispatch" could look like? 3) Assuming an outage of a single transmission line (N-1 Category B event) has occurred and assuming that no "resources [are] obligated to redispatch" for this outage, would a transmission provider be allowed to curtail Firm Transmission Service that it has sold in order to prepare to withstand the next worst credible contingency? 4) Would transmission providers be allowed to sell Firm Transmission Service on a path above what could be delivered with any one element of that path out of service across a range of operating conditions? 5) If the proposed Footnote b is approved, and assuming an appropriate obligation to redispatch could not be negotiated, would utilities have to reinforce their system (within 60 months) to ensure that Firm Transmission Services already sold on particular paths would not be curtailed when any one element of that path is out of service? 6) If a transmission provider employs Generation Dropping for single contingencies in order to support Firm Transmission Service between regions, and assuming there are no provisions for obligated re-dispatch, would the proposed Footnote b force a recalculation of firm vs non-firm transfer capability? 7) Path 66 (PACI) and Path 65 (PDCI) can both see significant derates in their firm transfer capability for single contingencies. How would the proposed Footnote b impact Firm Transmission on these paths? Further, the Project 2010-11 SDT (Footnote "b") should be amalgamated with the Project No. 2006-02 SDT (TPL-001 through TPL004 amalgamation/update): 1. It doesn't make any sense to update Footnote "b" of TPL-001 based on the existing approved

Balloter	Company	Seg-ment	Vote	Comment
				version of TPL-001 when the language in that standard is being revised and terms that Footnote “b” makes reference to will be changed. Draft #6 (2010-Oct-19) of TPL-001 has changed “Footnote b” to “Footnote 9”. 2. Draft #6 of TPL-001 has changed the column heading relevant to “Footnote b” from “Loss of Demand or Curtailed Firm Transfers” to “Interruption of Firm Transmission Service Allowed”. 3. Draft #6 of TPL-001 has seven new definitions including the following two definitions that would be expected to be relevant to Footnote b: 3.1. Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault. 3.2. Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment. 4. The Project 2006-02 SDT has placed Draft #6 of TPL-001 on hold, stating, “The team will delay moving the standard forward until the resolution of “footnote b” has become clear.”
Response: 1. For consistency with the existing standard text, the term ‘firm transfer’ is retained. Therefore, the interpretation of “firm transfers” remains unchanged. 2. One example would be a contractual arrangement that defines clear expectations to alternately serve Load upon the removal of the firm transfer so that no loss of Load occurs. 3. In the planning timeframe, footnote ‘b’ addresses single Contingencies (Cat. B) and footnote ‘c’ addresses the Cat. C Contingencies. Neither footnote prohibits System adjustments, which could include re-dispatch of your own resources to prepare for the next Contingency. 4. How Firm Transmission Service (FTS) is sold is addressed in individual tariffs in concert with the MOD standards. 5. The implementation plan provides 60 months after regulatory approval for entities to comply with the modified standard. How that is accomplished is up to individual entities. 6. & 7 Each circumstance may need to be evaluated individually and additional documentation of understandings may be necessary. 7-1 - 4. Based on ballot comments and regulatory orders, the SDT determined that the best course of action was to address footnote ‘b’ as a standalone item and then incorporate the changes approved for footnote ‘b’ into the new TPL-001-2 in a manner consistent with the other proposed changes in TPL-001-2.				
Christopher L de Graffenried	Consolidated Edison Co. of New York	1	Negative	Interruptible Demand, like Demand-Side-Management, is an operational tool. We do not believe it appropriate to use operational tools for transmission planning. A load serving entity should not claim to serve loads it plans to disconnect during a design contingency. In other words, these loads should be excluded from the load forecast in the first place and, thereby, would not be represented in power flows that are utilized to assess system performance under the TPL standards. This approach prevents the use of such load interruptions to address any deficiency found in TPL-type
Peter T Yost	Consolidated Edison Co. of New York	3	Negative	

Balloter	Company	Seg-ment	Vote	Comment
Wilket (Jack) Ng	Consolidated Edison Co. of New York	5	Negative	assessments.
Nickesha P Carrol	Consolidated Edison Co. of New York	6	Negative	
Response: Entities across the continent have many different Interruptible and Demand-Side Management programs that have many different attributes and rules. Some entities have Interruptible Demand programs that are appropriate for planning purposes.				
Chuck B Manning	Electric Reliability Council of Texas, Inc.	2	Negative	The introductory paragraph of footnote b includes policy language. Since this is a reliability standard-and not a policy directive-the general narrative setting forth the desired policy goal of minimizing load-shedding is misplaced. Including policy language can cloud the specific issues the standard attempts to address, and ERCOT recommends deleting the first two sentences in the introductory paragraph. The next sentence in the introductory paragraph goes on to state, generally, that demand may be interrupted to "address BES performance requirements.” This phrase is vague. To which performance requirements does this refer? The intent is not clear. If the intent is to generally recognize the need to shed load to respect to NERC standards and to allow flexibility for an entity to exercise discretion relative to meeting BES performance requirements, then that intent should be clearly reflected in the language. Furthermore, the last sentence of the introductory paragraph and the subsequent bullet points are arguably inconsistent with this approach, because they could be viewed as removing an entity’s flexibility/discretion by limiting the circumstances when load can be shed. The second bullet point is unnecessary, because it is already apparent that interruptible demand/demand side management programs can be used according to their terms. This could create confusion in that it could be implied that, absent the need to use these to meet BES performance requirements, using them otherwise is inconsistent with/not allowed under footnote b. Simply put, those products are not load shedding as contemplated by this footnote. Therefore they should not be listed here. With respect to the third bullet point, the phrase "demand that does not adversely impact overall BES reliability" is not adequately defined, and provides opportunity for confusion. This is an ambiguous phrase and can’t be linked back to objective NERC standards/requirements. The bullet points should avoid ambiguity to mitigate ambiguity risk in audits.

Balloter	Company	Seg-ment	Vote	Comment
				In addition, the last part of the language in this bullet imposing an open and transparent stakeholder process is unclear. What is the intent behind requiring review in a stakeholder process? If it is to establish the ability of the entity to develop load shedding procedures beyond those explicitly contemplated in footnote b, ERCOT questions if it is reasonable for the responsible entity to be required to get "permission" from stakeholders to implement reliability measures related to its obligation as the functional entity. Again, the language simply is not clear. Accordingly, ERCOT recommends this bullet point be removed. If it is retained, it should be revised consistent with these comments to remove ambiguous language to mitigate potential confusion around the meaning/scope of the footnote in the administration of the CMEP. In addition, ERCOT recommends revising the draft footnote b to allow for planned Demand interruption as a means of mitigation during interim periods when a unanticipated (such as unexpected demand growth or unit retirements) or temporary change on the system occurs in a timeframe that is shorter than the time necessary to plan and implement the system upgrades necessary to avoid the Demand interruption. Finally, in the last paragraph of footnote b, it isn't clear why "Transmission Service" was changed to "transfers." Firm transmission service is a service provided in some regions, and it provides relative value to other types of services-e.g., non-firm and network. The mention of transmission service may also be irrelevant in this footnote, since the allowance of its interruption doesn't also allow for load shedding. Therefore, ERCOT recommends eliminating the last paragraph of footnote b.

Response: The SDT believes that the first part of the footnote is necessary to provide context for the items that follow and has crafted the language to provide a balance between flexibility and consistency across NERC. No change made.

The term "BES performance requirements" references the other requirements within the TPL standard and the SDT has removed the phrase "demand that does not adversely impact overall BES reliability".

In a previous posting, entities had stated that it was not clear that the use of Interruptible Load and Demand Side Management was permitted. The SDT added this section to address those concerns. The SDT has reorganized and reformatted the footnote to improve clarity.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm

<table>
<tr><th>Balloter</th><th>Company</th><th>Seg-ment</th><th>Vote</th><th>Comment</th></tr>
<tr><td colspan="5">Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

The open and transparent process does not require "permission", but rather it facilitates the open sharing of information between entities that have responsibility for ensuring BES reliability.

The SDT decided to not limit the use of the footnote to a specific time period because there are circumstances where the longer term use may be implemented without adversely impacting BES reliability.

For consistency with the existing standard text, the term 'firm transfer' is retained. No change made.</td></tr>
<tr><td>Claudiu Cadar</td><td>GDS Associates, Inc.</td><td>1</td><td>Negative</td><td>We appreciate all the work conducted by SDT to adjust current footnote "b" however, we disagree with the current approach mainly from the same reasons iterated during last comment period, as follows:
• The definition does not go far enough with recognition that interruption of Demand should be mitigated if at all possible. The language should encourage the TP to develop mitigation plans that could be implemented as an alternative to Demand interruption.

• Use of Interruptible Demand should only be implemented if the Transmission Planner can point to a contract between the Transmission Provider and Transmission Customer that permits load curtailment.

• Under FERC Order 890, Conditional Firm transmission service can be granted for entities who voluntarily acknowledge the right of the Transmission Provider to curtail their transaction or provide re-dispatch. This should be the only transfer which can be utilized in the Planning Horizon for interruption of Demand for Note b.

We suggest using the following wording as emphasized below: "An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events and to develop mitigation plans that do not call for the curtailment of Demand.</td></tr>
</table>

Balloter	Company	Seg-ment	Vote	Comment
				It is recognized that Demand will be interrupted if it is directly served by the elements removed from service as a result of the Contingency and in very limited circumstances when approaching intermediate solutions to restore BES reliability. When interruption of Demand is utilized within the planning process, such interruption is limited to: ? Demand that is directly served by the elements that are removed from service as a result of the Contingency, ? Interruptible Demand or Demand-Side Management, where the Customer has given explicit rights to the Transmission Provider for curtailment of their Demand, ? Demand, other than Interruptible Demand or Demand-Side Management, that does not adversely impact overall BES reliability where the circumstances describing the use of such Demand are documented, including alternatives evaluated; where the Load-Serving Entity who has responsibility for serving such Demand has agreed to the curtailment, and where the application is subject to review and acceptance in an open and transparent stakeholder process. Curtailment of Firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch per the terms and conditions of the confirmed transmission service request between the Transmission Customer and Transmission Provider, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected. In addition, any Conditional Firm transfers may be curtailed, in accordance with the terms and conditions of the confirmed transmission service request between the Transmission Customer and Transmission Provider."
Response: In the footnote, the SDT has acknowledged that interrupting Firm Demand is not the preferred solution to BES concerns, while recognizing that this may not always be possible. The SDT believes that the footnote as drafted strikes an appropriate balance. No change made. It is well understood that there must be some agreement or contract before interruptible Demand or Demand-Side Management can be utilized by the planner. The SDT disagrees that there should be a prohibition on utilizing other resources obligated to re-dispatch for Contingencies, unless it has been characterized as "conditional firm". Entities should not be restricted from utilizing other dispatch scenarios, as long as Firm Demand is not interrupted. For the reasons stated above, the SDT has not modified the footnote as suggested.				
Joe D Petaski	Manitoba Hydro	1	Negative	The last bullet should be made clearer by adding the words "in jurisdictions" before the word "where". Not all jurisdictions are mandated to have a stakeholder process, so the standard should be clearly written to recognize this situation. "Circumstances where the use of Demand interruption are documented, including alternatives evaluated; and IN JURISDICTIONS where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments."
Greg C. Parent	Manitoba Hydro	3	Negative	
S N Fernando	Manitoba Hydro	5	Negative	
Daniel	Manitoba Hydro	6	Negative	

Balloter	Company	Seg-ment	Vote	Comment
Prowse				
Response: The SDT believes that if Firm Demand is planned to be interrupted utilizing footnote 'b', there must be an open and transparent stakeholder process to ensure that all parties that may be impacted have been notified and have an opportunity to provide comments. No change made.				
Spencer Tacke	Modesto Irrigation District	4	Negative	I am voting NO on the proposed revision because the second bullet of the proposed revision is nebulous as to how the exemption process will occur, and how it will be monitored by the auditors. Also, the last sentence of the last paragraph of the proposed change is nebulous about keeping facility flows within applicable Normal and Emergency thermal ratings. Thank you.
Response: Rather than mandate a one-size-fits-all process, the SDT has provided entities the latitude to utilize existing processes, modify existing processes, or create new processes to provide an open and transparent stakeholder process. The SDT cannot comment on future actions of the auditors. The SDT disagrees that maintaining Facilities within applicable Facility Ratings is a nebulous concept. That part of the footnote was included to ensure that the plans to resolve a situation on a planner's System did not create other overloads. No change made.				
Saurabh Saksena	National Grid	1	Negative	National Grid supports the direction the drafting team has taken. However, it has a few concerns with the language of the footnote as amended. 1. Use of the term "Demand": In the first sentence, it is unclear whether the term Demand includes Interruptible Demand and Demand-Side Management. It is suggested that interruption of Demand be clarified to exclude Interruptible Demand or Demand-Side Management. 2. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet.

Balloter	Company	Seg-ment	Vote	Comment
Michael Schiavone	Niagara Mohawk (National Grid Company)	3	Negative	3. National Grid also suggests changing "Demand interruption" to "interruption of Demand" in second bullet under "b)" to avoid awkward and incorrect phasing. 4. 'Addressing stakeholder comments' introduces undefined actions which may be required in response to the comments. If 'Demand interruption is subject to review in an open and transparent stakeholder process', then stakeholder comments will be addressed without creating an undefined commitment to require it. As a result, "that includes addressing stakeholder comments" should be deleted. 5. The second paragraph seems to be restricting the use of Demand interruption for the sake of Firm Transfer reduction. This can be stated directly without adding the confusion of re-dispatch. By coupling re-dispatch with a constraint of not shedding Demand, the paragraph also creates confusion as to what to do in a situation where the amount of Demand that is allowed to be shed in the first paragraph could be reduced with re-dispatch. Would re-dispatch not be allowed? National Grid suggests that the paragraph be rewritten as follows: 'Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management).' 6. National Grid seeks clarification if there is an intended distinction between the use of the term "firm Demand" and the defined term "Firm Demand" or is that just a typo? 7. The last sentence of footnote B is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own. This same thought would have to be added to multiple NERC standards if it were added here, otherwise it would infer that such actions are acceptable in all other standards.

Response: 1. The SDT has reorganized the text in the footnote to address this concern.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

Balloter	Company	Seg-ment	Vote	Comment
~~Interruptible Demand or Demand-Side Management~~ ~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~ **2.** The SDT has reorganized the text in the footnote to address this concern. **3.** The SDT believes that the proposed change does not add additional clarity to the footnote. No change made. **4.** The SDT disagrees that each review process automatically will have a response to comments element. Therefore, the SDT added that element to ensure that all stakeholder processes will include that element. No change made. **5.** The SDT has reorganized the text in the footnote to address this concern. **6.** The SDT has corrected the capitalization errors. **7.** Since the planned action of curtailing of firm transfers may adversely impact neighboring systems, the SDT believes that it is important in this situation to articulate a condition that is normally implied. The SDT disagrees that an explicit statement in this footnote changes the intent of all other standards. No change made.				
Tony Eddleman	Nebraska Public Power District	3	Negative	NPPD votes NO due to the ambiguity of the terms "Curtailment of firm transfers is allowed, when coupled the appropriate re-dispatch of resources" with respect to a Category B contingency event. NPPD does not support the curtailment of firm transfers or re-dispatch to meet the performance requirements during a Category B (N-1) event. Curtailment of firm transfers and re-dispatch are allowable following acceptable performance for the Category B (N-1) event, to get ready for the next Category C type of event.
Don Schmit	Nebraska Public Power District	5	Negative	
Response: As drafted, footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can only be utilized for a limited time, such as a 2 hour emergency rating. It further clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the firm transfers cannot be curtailed. No change made.				

Balloter	Company	Seg-ment	Vote	Comment
Randy MacDonald	New Brunswick Power Transmission Corporation	1	Negative	In general: NERC standards should not dictate circumstances or acceptable transmission contingencies under which the tripping of customers loads is acceptable. That should be an issue between the utility of supply, the customer, and the local regulating body so long as the interruption to customers (for whatever contingency) is controlled and does not cause problems on the BES, or to neighboring utilities. Specifically, 1. The second bullet: The last sentence (following the semicolon) should be removed. The local regulating body should provide input or approval. 2. NB Power Transmission interprets that the currently proposed footnote allows for the two bulleted options to be used exclusively or in combination. Thus for clarification suggest adding "or" after the first bulleted item.

Response: The SDT disagrees that this should be handled exclusively with the local regulating body. The SDT believes that in situations where an entity's planning studies require the interruption of Firm Demand to remain within BES Facility Ratings that the entity needs to share those plans in an open and transparent stakeholder process to ensure that other parties that may be adversely impacted by those decisions have the ability to review those plans**.** No change made.

The SDT has reorganized the footnote to clarify its intent and address the issue raised.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~-C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

Balloter	Company	Seg-ment	Vote	Comment
Alden Briggs	New Brunswick System Operator	2	Negative	NBSO agrees with the principles of the current version of the proposed footnote assuming NBSO's interpretation of the footnote is correct. NBSO has the following detailed comments: 1. The first paragraph contains many general statements that attempts to capture essential planning principles. NBSO feels that such language is not suited for a footnote. NBSO suggests re-wording of the first paragraph to state: Interruption of Demand may be utilized within the planning process to address BES performance requirements. Such cases are limited to: NBSO also suggests turning the phrase that addresses Demand lost that was served by elements removed from service as a result of a Contingency into a bullet item. NBSO feels that this adds clarity since all of the acceptable instances of Demand interruption are now listed as bulleted items. 2. NBSO interprets that the currently proposed footnote allows for the two bulleted options to be used exclusively or in combination. Thus for clarification NBSO suggests adding "or" after each bulleted item, with the exclusion of the final bulleted item. 3. NBSO suggests removing the last sentence of the last paragraph. Likely all industry members understand that causing reliability concerns in other areas is never acceptable. This principle is not limited to the standard in question, and thus such a statement could require the update of other standards. 4. NBSO interprets that the use of the word "Demand" in the second bullet of the proposed footnote is referring to use of Firm Demand since the first bullet covers the other types of Demand (Demand = Firm Demand + Interruptible Demand). As such NBSO suggests replacing "Demand" with "Firm Demand" in the second bullet. 5. NBSO feels that the statement "that includes addressing stakeholder comments" should be removed from the last phrase of the second bullet. An open and transparent stakeholder process should adequately address stakeholder comments and concerns. Explicitly specifying that all stakeholder comments be addressed may add undue burden if the word "address" is misconstrued. The task of addressing stakeholder comments is more appropriately addressed and defined in each area's respective process. 6. NBSO suggests replacing the word "shedding" with "interruption" in the last phrase of the last paragraph to remain consistent with the rest of the proposed footnote. NBSO also suggests capitalizing "firm" in the term "Firm Demand" to remain consistent with the NERC glossary of terms.

Balloter	Company	Seg-ment	Vote	Comment
				7. There is no term "transfers" in the NERC glossary of terms. Perhaps some other defined term from the glossary could be used in lieu of "transfers" (e.g. Firm Transmission Service). Taking into account the NBSO comments, the footnote could read as follows: b) Interruption of Demand may be utilized within the planning process to address BES performance requirements. Such cases are limited to: -Demand directly served by Elements removed from service as a result of a Contingency, or -Use of Interruptible Demand or Demand-Side Management, or -Interruption of Firm Demand when acceptable circumstances for such interruptions are documented (including alternatives evaluated), and where the Firm Demand interruption is subject to review in an open and transparent stakeholder process. Curtailment of Firm Transmission Service is allowed when coupled with the appropriate re-dispatch of resources obligated to do so, and it can be demonstrated that Facilities remain within applicable Facility Ratings and there is no additional interruption of Firm Demand.

Response: 1 & 2. The SDT believes that the first part of the footnote is necessary to provide context for the items that follow and has crafted the language to provide a balance between flexibility and consistency across NERC. The SDT has reorganized the footnote to clarify its intent and address the issue raised.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~-C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

3. Since the planned action of curtailing of firm transfers may adversely impact neighboring Systems, the SDT believes that it is important in this situation to articulate a condition that is normally implied. The SDT disagrees that an explicit statement in this footnote changes the intent of all other standards.
4. The SDT has reorganized the footnote to clarify its intent and address the issue raised.
5. The SDT believes that in situations where an entity's planning studies require the interruption of Firm Demand to remain within BES Facility Ratings that the

Balloter	Company	Seg-ment	Vote	Comment
entity needs to share those plans in an open and transparent stakeholder process to ensure that other parties that may be adversely impacted by those decisions have the ability to review those plans. No change made. **6.** The SDT does not believe that replacing the term shedding with interruption adds clarity and did not make the proposed change. The SDT has reorganized the footnote to clarify its intent and address the second issue. **7.** For consistency with the existing standard text, the term 'firm transfer' is retained. No change made.				
David H. Boguslawski	Northeast Utilities	1	Negative	The revised language of Footnote b suggests that non-consequential demand interruption (load that is not directly served by the elements removed from service as a result of the contingency) could be used to mitigate reliability concerns arising from NERC Category B contingency events (i.e., single element contingencies). This language seems to encourage operational workarounds and adds burdens for operators of the system. NU believes this is not consistent with planning a highly reliable bulk electric system and thus does not support this weaker language.
Response: The SDT believes that the language in this footnote is not weaker and does not encourage operational workarounds. The footnote language provides the framework necessary to ensure that in situations where an entity's planning studies require the interruption of Firm Demand to remain within BES Facility Ratings that the entity needs to share those plans in an open and transparent stakeholder process to ensure that other parties that may be adversely impacted by those decisions have the ability to review those plans. No change made.				
Brad Chase	Orlando Utilities Commission	1	Negative	"Two Items prevent us from voting yes. Item #1: The standard team should clarify if the bullets under note B are intended to be an AND (both conditions met) or an OR (either condition met). As currently written it is not clear. Item #2: The section under firm transfers is in conflict with the section above. If Demand is being curtailed under the first or second bullet and it's served by firm service then service should also be curtailed, however as written any demand served by firm service could not be curtailed. Other then these items the revisions does an excellent job of addressing the issue of load shedding under first contingency conditions and practical reliablity."
Ballard Keith Mutters	Orlando Utilities Commission	3	Negative	
Response: The SDT has reorganized the footnote to clarify its intent and address this issue. b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~ ~~Interruptible Demand or Demand-Side Management~~				

Balloter	Company	Seg-ment	Vote	Comment
				~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~
Linda Brown	San Diego Gas & Electric	1	Negative	Footnote b is a group of exceptions to the requirements for Category B contingencies. To add clarity to the footnote, SDG&E would prefer that each exception be listed separately within the footnote. As SDG&E understands the footnote, the following exceptions can occur after the loss of a single element, • Interruptible Demand can be used to unload a circuit, but the circuit(s) must remain below emergency rating(s) at all times. • Demand-Side Management can be used to unload a circuit, but the circuit(s) must remain below emergency rating(s) at all times. • Demand served by a radial element which is faulted may be interrupted. • Curtailment of firm transfers is allowed, when coupled with re-dispatch of resources obligated to re-dispatch. SDG&E votes against the proposed language for the following reasons: SDG&E feels system reliability alone should drive the need for a technical standard and the language of the standard should reflect the need without reference to the process. FERC Order 890 set the forum for the stakeholder process which provides commercial incentives and a level playing field for any participant to build a transmission project. When considering compliance to the standards, reference to "stakeholder process" is inappropriate and should be removed. Section 4 of the TPL standards assigns responsibility for meeting the standards to the Planning Authority and the Transmission Planner. These entities are subject to penalties if the requirement is not met. Use of "stakeholder process" in the requirement implies that entities other than the Planning Authority or the Transmission Planner have authority over how the standards are to be met without any financial risk. If the "stakeholder process" language is not removed, SDG&E feels stakeholders involved in the process should be registered with NERC and subject to the same audit requirements and penalties as the Planning Authority or the Transmission Planner. Furthermore, the California Transmission Owners have a FERC approved stakeholder process that is administered by the California ISO. Addition of the term "stakeholder process" in a standard may have unintended consequences.

<table>
<tr><th>Balloter</th><th>Company</th><th>Seg-
ment</th><th>Vote</th><th>Comment</th></tr>
<tr><td colspan="5">

Response: While the SDT believes that SDG&E proposed bullet list is consistent with the footnote as drafted, the list is not as inclusive as the footnote. Therefore, the SDT has retained the existing text and reorganized the footnote for clarity.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

The SDT believes that in situations where an entity's planning studies require the interruption of Firm Demand to remain within BES Facility Ratings that the entity needs to share those plans in an open and transparent stakeholder process to ensure that other parties that may be adversely impacted by those decisions have the ability to review those plans. No change made.

</td></tr>
<tr><td>Charles H Yeung</td><td>Southwest Power Pool</td><td>2</td><td>Negative</td><td>The second paragraph of the footnote seems to be restricting the use of Demand interruption for the sake of Firm Transfer reduction. This can be stated directly without adding the confusion of re-dispatch. By coupling re-dispatch with a constraint of not shedding Demand, the paragraph also creates confusion as to what to do in a situation where the amount of Demand that is allowed to be shed in the first paragraph could be reduced with re-dispatch. Would re-dispatch not be allowed? We suggest that the paragraph be rewritten as follows: "Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management)."</td></tr>
<tr><td colspan="5">

Response: The SDT has reorganized the footnote to clarify its intent and address this issue.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch,

</td></tr>
</table>

Balloter	Company	Seg-ment	Vote	Comment
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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~ ~~Interruptible Demand or Demand-Side Management~~ ~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~				
Larry Akens	Tennessee Valley Authority	1	Negative	TVA appreciates the SDT's efforts to clarify and improve this complex and challenging area. However, as mentioned in our last comments regarding footnote b, TVA still believes that the SDT's proposal is still focusing more on reliability of local loads than on the overall reliability of the BES. Reliability of local loads should be addressed outside the TPL standards and therefore should not be used/referenced in footnote b. Existing stakeholder processes (referred to in the SDT proposal) typically focus on larger system issues and not on local load serving. TVA believes that some local load should be allowed to be dropped in order to maintain BES reliability. Instead of the proposed footnote b, TVA suggests that the SDT define a "local area" with guidelines detailing the reliability requirements for these local area loads. This would separate the local area load requirements from the BES requirements in the TPL standards.
Ian S Grant	Tennessee Valley Authority	3	Negative	
George T. Ballew	Tennessee Valley Authority	5	Negative	
Marjorie S. Parsons	Tennessee Valley Authority	6	Negative	
Response: The original footnote 'b' focused on local area and limited interruption of Demand. Since individual entities planning philosophies are different across North America, the SDT has been unable to determine a one-size-fits-all definition for local area. Therefore, the SDT adopted an approach that allows entities to utilize input from stakeholders in an open and transparent process. In this way, any affected party has a mechanism to ensure that the planners are planning a reliable BES. No change made.				
Pat G. Harrington	BC Hydro and Power Authority	3	Negative	
Gordon Rawlings	BC Transmission Corporation	1	Negative	
Response: With no comment provided, the SDT is unable to provide a response.				
Gregg R Griffin	City of Green Cove Springs	3	Affirmative	An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will

Balloter	Company	Seg-ment	Vote	Comment
				be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: Interruptible Demand or Demand-Side Management Circumstances where the uses of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.
Response: Thank you for your support.				
Guy V. Zito	Northeast Power Coordinating Council, Inc.	10	Affirmative	1. There is concern with the use of the term Demand. It is unclear throughout the footnote whether or not the term Demand includes Interruptible Demand or Demand-Side Management. It is suggested that interruption of Demand be clarified to not include Interruptible Demand or Demand-Side Management to more clearly show the permitted use of Load shedding. 2. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. 3. Language that mitigation of Load and/or Demand interruption should be pursued within the planning process should be reinstated as reinforcement of a Transmission Providers' planning obligations to their load customers, and system operations. 4. Footnote 'b' should be made to read as follows: b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of Load and/or Demand following Contingency events. Interruption of Load and/or Demand is discouraged and all measures to mitigate such interruption should be pursued within the planning process. However, it is recognized that Load and/or Demand will be interrupted if it is directly served by the elements automatically removed from service by the Protection System as a result of a Contingency. Furthermore, in extraordinary circumstances within the planning process Load and/or Demand may need to be interrupted to address BES performance requirements. When interruption of Load and/or Demand is utilized within the planning

Balloter	Company	Seg-ment	Vote	Comment
				process to address BES performance requirements, such interruption is limited to: • Circumstances where the use of Load and/or Demand interruption are documented, including alternatives evaluated; and where the Load and/or Demand interruption is made available for review in an open and transparent stakeholder process. If Load and/or Demand interruption is necessary, planning should indicate the amount needed, and not specify how it would be obtained. What Load and/or Demand is interrupted is an operational decision. 5. Additional comments not included in the material listed for footnote 'b' on the Comment Form. In the paragraph below the bullets in footnote 'b', confusion is introduced through the use of the term "firm Demand". It is unclear how this is different than the defined term "Firm Demand" and what the implications of the term "firm Demand" are. This footnote should not discourage such adjustments which actually increase the reliability of service to end users. 6. The last sentence of footnote 'b' is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own.

Response: 1. The SDT has reorganized the footnote to clarify its intent and address this issue.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~-C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

2. The SDT has reorganized the footnote to clarify its intent and address the issue raised.

Balloter	Company	Seg-ment	Vote	Comment
Ajay Garg	Hydro One Networks, Inc.	1	Affirmative	Hydro One is casting an affirmative vote on the revisions to Table 1, footnote 'b' in TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. However, we believe the proposed language might be confusing and should be modified to read as follows: "b) It is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Interruptible Demand or Demand-Side Management o Circumstances where the uses of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the interruption of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected." Note that the voting system does not permit to enter re-lined comments. We can provide a red-lined document with our proposal upon request.
David L Kiguel	Hydro One Networks, Inc.	3	Affirmative	

3. & 4. The SDT addressed these concerns by including the phrase "including alternatives evaluated" and does not believe that it is appropriate to dictate that the planners must evaluate "all measures to mitigate" annually or the specific details concerning documentation of alternatives.
5. The SDT has corrected the capitalization errors.
6. Since the planned action of curtailing of firm transfers may adversely impact neighboring systems, the SDT believes that it is important in this situation to articulate a condition that is normally implied. No change made.

Response: The SDT believes that the sentences deleted in your proposed footnote are necessary to provide context for the items that follow and has crafted the language to provide a balance between flexibility and consistency across NERC. The SDT has reorganized the footnote to clarify its intent.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

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~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~				
Henry Ernst-Jr	Duke Energy Carolina	3	Affirmative	The effective date in the Implementation Plan needs to be changed to match the Effective Date in the standards, in order to clarify the allowed interruption of Non-consequential load before the new Footnote 'b' takes effect.
Response: The effective dates in the Implementation Plan match those in the standards. No change made.				
Mark B Thompson	Alberta Electric System Operator	2	Abstain	While the AESO does not generally disagree with the intent of the proposed change, we have voted "abstain". In particular, as reflected in the adopted Alberta Reliability Standard TPL-002-AB-0, no loss of Demand and Generation have been given equal consideration for Category B contingencies. In addition, within the Alberta energy market structure and the operation of the transmission system, there are no firm transfers on transmission facilities in Alberta.
Response: Individual jurisdictions are allowed to have more restrictive standards and therefore, this revision to the standard does not dictate that a jurisdiction must change its requirements. The SDT recognizes that there may be areas or markets that do not utilize terms contained within the standard.				

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. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Standards re-posted in September 2010.
6. Re-balloted in December 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

These changes were balloted and received approval but several commenters requested clarifications of the SDT’s intent. The SDT responded to these requests by re-ordering the items in footnote ’b’ to make it clear exactly what the intent of the changes were.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Recirculation ballot	January 2011
2. Submit to BOT for approval	January 2011
3. File with FERC	February 2011

A. Introduction

1. Title: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. Number: TPL-004-1

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-1_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-1_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating[a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No[b] No[b] No[b] No[b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

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. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Standards re-posted in September 2010.
6. Re-ballotted in December 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote 'b' to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

These changes were balloted and received approval but several commenters requested clarifications of the SDT's intent. The SDT responded to these requests by re-ordering the items in footnote 'b' to make it clear exactly what the intent of the changes were.

Future Development Plan:

Anticipated Actions	Anticipated Date
~~1. 30-day posting~~	~~September 2010~~
~~2. 30-day pre-ballot period~~	~~November 2010~~
~~3. Initial ballot~~	~~December 2010~~
~~4~~1. Recirculation ballot	January 2011
~~5~~2. Submit to BOT for approval	January 2011
~~6~~3. File with FERC	February 2011

A. Introduction

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. **Number**: TPL-004-1

3. **Purpose**: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability**:

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-1_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-1_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

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~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

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c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

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1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

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- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
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The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

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Future Development Plan:

Anticipated Actions	**Anticipated Date**
1. Recirculation ballot	January 2011
2. Submit to BOT for approval	January 2011
3. File with FERC	February 2011

A. Introduction

1. Title: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. Number: TPL-004-~~0~~1

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

~~**5. Effective Date:** April 1, 2005~~

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-~~0~~1_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-~~0~~1_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Revised footnote 'b' pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

~~b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

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. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
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6. Re-balloted in December 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

These changes were balloted and received approval but several commenters requested clarifications of the SDT’s intent. The SDT responded to these requests by re-ordering the items in footnote ’b’ to make it clear exactly what the intent of the changes were.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Recirculation ballot	January 2011
2. Submit to BOT for approval	January 2011
3. File with FERC	February 2011

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-1a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote ‘b’ in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-1_R1 and TPL-003-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information
None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
1a	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

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. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
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6. Re-ballotted in December 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote 'b' allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote 'b' were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term 'fringes' was seen as problematic and application at the 'fringes' could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote 'b'. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote 'b' in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote 'b' to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

These changes were balloted and received approval but several commenters requested clarifications of the SDT's intent. The SDT responded to these requests by re-ordering the items in footnote 'b' to make it clear exactly what the intent of the changes were.

Future Development Plan:

Anticipated Actions	Anticipated Date
~~1. 30-day posting~~	~~September 2010~~
~~2. 30-day pre-ballot period~~	~~November 2010~~
~~3. Initial ballot~~	~~December 2010~~
1.~~4.~~ Recirculation ballot	January 2011
2.~~5.~~ Submit to BOT for approval	January 2011
3.~~6.~~ File with FERC	February 2011

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-1a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-1_R1 and TPL-003-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
1a	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) ~~-~~directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements,, such interruption is limited to~~:~~

~~o Interruptible Demand or Demand-Side Management~~

~~-C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected~~

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

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. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Standards re-posted in September 2010.
6. Re-balloted in December 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote 'b' allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote 'b' were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term 'fringes' was seen as problematic and application at the 'fringes' could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote 'b'. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote 'b' in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

These changes were balloted and received approval but several commenters requested clarifications of the SDT’s intent. The SDT responded to these requests by re-ordering the items in footnote ’b’ to make it clear exactly what the intent of the changes were.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Recirculation ballot	January 2011
2. Submit to BOT for approval	January 2011
3. File with FERC	February 2011

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-~~0a~~1a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

~~5. **Effective Date:** April 23, 2010~~

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-~~0~~1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-~~0~~1_R1 and TPL-003-~~0~~1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-~~0~~1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item "e" on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
~~0a~~1a	~~April 23, 2010~~TBD	~~FERC approval of interpretation of TPL-003-0 R1.3.12~~Revised footnote 'b' pursuant to FERC Order RM06-16-009.	~~Interpretation~~Revised

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Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes	 No [b] No [b] No [b]	 No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

~~b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2
Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

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. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Standards re-posted in September 2010.
6. Re-balloted in December 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote 'b' allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote 'b' were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term 'fringes' was seen as problematic and application at the 'fringes' could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote 'b'. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote 'b' in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

These changes were balloted and received approval but several commenters requested clarifications of the SDT’s intent. The SDT responded to these requests by re-ordering the items in footnote ’b’ to make it clear exactly what the intent of the changes were.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Recirculation ballot	January 2011
2. Submit to BOT for approval	January 2011
3. File with FERC	February 2011

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-1b

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-1_R1 and TPL-002-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	April 2010	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section - - - - - - - - - - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - - - - - - - - - - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

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TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

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. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Standards re-posted in September 2010.
6. Re-ballotted in December 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

These changes were balloted and received approval but several commenters requested clarifications of the SDT’s intent. The SDT responded to these requests by re-ordering the items in footnote ’b’ to make it clear exactly what the intent of the changes were.

Future Development Plan:

Anticipated Actions	Anticipated Date
~~1. 30-day posting~~	~~September 2010~~
~~2. 30-day pre-ballot period~~	~~November 2010~~
~~3. Initial ballot~~	~~December 2010~~
~~4~~1. Recirculation ballot	January 2011
2. Submit to BOT for approval	January 2011
3. File with FERC	February 2011

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-1b

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-1_R1 and TPL-002-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	April 2010	Revised footnote 'b' pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section - - - - - - - - - - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - - - - - - - - - - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected.~~

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

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. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Standards re-posted in September 2010.
6. Re-balloted in December 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote 'b' to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

These changes were balloted and received approval but several commenters requested clarifications of the SDT's intent. The SDT responded to these requests by re-ordering the items in footnote 'b' to make it clear exactly what the intent of the changes were.

Future Development Plan:

Anticipated Actions	**Anticipated Date**
1. Recirculation ballot	January 2011
2. Submit to BOT for approval	January 2011
3. File with FERC	February 2011

A. Introduction

1. **Title:** **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. **Number:** TPL-002-~~0b~~1b

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

~~5. **Effective Date:** Immediately after approval of applicable regulatory authorities.~~

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories~~,~~, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-~~0~~1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-~~0~~1_R1 and TPL-002-~~0~~1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-~~0~~1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	April 2010	Revised footnote 'b' pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

~~b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

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. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Standards re-posted in September 2010.
6. Re-balloted in December 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote 'b' allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote 'b' were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term 'fringes' was seen as problematic and application at the 'fringes' could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote 'b'. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote 'b' in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

These changes were balloted and received approval but several commenters requested clarifications of the SDT’s intent. The SDT responded to these requests by re-ordering the items in footnote ’b’ to make it clear exactly what the intent of the changes were.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Recirculation ballot	January 2011
2. Submit to BOT for approval	January 2011
3. File with FERC	February 2011

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)

2. **Number:** TPL-001-1

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-1_R1 and TPL-001-1_ R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

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. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Standards re-posted in September 2010.
6. Re-ballotted in December 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote 'b' allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote 'b' were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term 'fringes' was seen as problematic and application at the 'fringes' could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote 'b'. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote 'b' in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

These changes were balloted and received approval but several commenters requested clarifications of the SDT’s intent. The SDT responded to these requests by re-ordering the items in footnote ’b’ to make it clear exactly what the intent of the changes were.

Future Development Plan:

Anticipated Actions	Anticipated Date
~~1. 30-day posting~~	~~September 2010~~
~~2. 30-day pre-ballot period~~	~~November 2010~~
~~3. Initial ballot~~	~~December 2010~~
1. ~~4.~~ Recirculation ballot	January 2011
2. ~~5.~~ Submit to BOT for approval	January 2011
3. ~~6.~~ File with FERC	February 2011

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)

2. **Number:** TPL-001-1

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote ‘b’ in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. **Measures**

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-1_R1 and TPL-001-1_ R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

	Contingencies	System Limits or Impacts

Category	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple)	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 3. Transformer	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and

elements removed or Cascading out of service.	2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is

due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

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. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Standards re-posted in September 2010.
6. Re-balloted in December 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote 'b' allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote 'b' were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term 'fringes' was seen as problematic and application at the 'fringes' could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote 'b'. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote 'b' in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote 'b' to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

These changes were balloted and received approval but several commenters requested clarifications of the SDT's intent. The SDT responded to these requests by re-ordering the items in footnote 'b' to make it clear exactly what the intent of the changes were.

Future Development Plan:

Anticipated Actions	**Anticipated Date**
1. Recirculation ballot	January 2011
2. Submit to BOT for approval	January 2011
3. File with FERC	February 2011

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)

2. **Number:** TPL-001-~~0.~~1

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

~~5. **Effective Date:** May 13, 2009~~

5. **Effective Date:** The application of revised Footnote ‘b’ in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-~~0~~1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-~~0~~1_R1 and TPL-001-~~0~~-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-~~0~~1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
Compliance Monitor: Regional Reliability Organization.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame
Annually

1.3. Data Retention
None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised

~~Table I. Transmission System Standards – Normal and Emergency Conditions~~

~~Category~~ 1	~~Contingencies~~ TBD	~~System Limits or Impacts~~ Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised

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Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

~~b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, 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 the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is

due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Implementation Plan for Project 2010-11: TPL Table 1 Order

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

Revision to Sections of Approved Standards and Definitions

There are no new definitions in the proposed standards.

Compliance with Standards

Standards	Functions That Must Comply With the Associated Requirements	
	Transmission Planner	Planning Authority
TPL-001-0.2: System Performance Under Normal (No Contingency) Conditions (Category A) TPL-002-0c: System Performance Following Loss of a Single Bulk Electric System Element (Category B) TPL-003-0b: System Performance Following Loss of Two or More Bulk Electric System Elements (Category C) TPL-004-0a: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)	X	X

Effective Dates

The effective date is the date entities are expected to meet the performance identified in this standard.

The effective date for footnote 'b' will be the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption.

All other requirements remain in effect as per previous approvals.

NERC
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Standards Announcement

Recirculation Ballot Window Open January 26-February 5, 2011
Project 2010-11 TPL Table 1 Order

Now available at: https://standards.nerc.net/CurrentBallots.aspx

A recirculation ballot window for standards TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1 is open **until 8 p.m. Eastern on Saturday, February 5, 2011**.

Instructions
Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx.

Ballot Process
The Standards Committee encourages all members of the ballot pool to review the consideration of comments submitted during the last ballot window. In the recirculation ballot, votes are counted by exception only — if a ballot pool member does not submit a revision to that member's original vote, the vote remains the same as in the first ballot. Members of the ballot pool may:

- Reconsider and change their votes from the first ballot
- Vote in the second ballot even if they did not vote on the first ballot
- Take no action if they do not want to change their original vote

Additional Information
The Standard Processes Manual allows drafting teams to make changes following an initial or successive ballot with a goal of improving the quality of a standard, provided those changes do not alter the applicability or scope of the proposed standard. Following the initial ballot the Project 2010-11 made minor changes to the structure of footnote 'b' in all of the standards, and corrected capitalization of NERC Glossary terms. The standards (clean versions, and redlines against the last posted and last approved versions) have been posted on the project page.

Next Steps
Voting results will be posted and announced after the ballot window closes. If approved, the standards and associated implementation plan will be submitted to the Board of Trustees.

Background
FERC Order RM06-16-009 requires the ERO to clarify TPL-002-0, Table 1 - footnote 'b,' regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system and originally directed NERC to file the revised standards by June 30, 2010. To meet this directive, a proposed revision was posted for "Urgent Action" and balloted from May 17-27, 2010. The proposed revision

achieved a quorum (84%) and almost enough affirmative votes (64%) to achieve weighted segment approval; however many balloters provided comments indicating the need for additional modifications. Following the initial ballot, FERC extended the due date to March 31, 2011; thus the project is no longer considered "Urgent Action."

Because Table 1 appears in TPL-001, TPL-002, TPL-003, and TPL-004, the change is reflected in all four standards:

- TPL-001-1 - System Performance Under Normal (No Contingency) Conditions (Category A)
- TPL-002-1b - System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- TPL-003-1a - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
- TPL-004-1 - System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

More details may be found on the project page:
http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

North American Electric Reliability Corporation
116-390 Village Blvd.
Princeton, NJ 08540
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Ballot Results	
Ballot Name:	Project 2010-11 TPL Table 1 Footnote B SAR_rc
Ballot Period:	1/26/2011 - 2/5/2011
Ballot Type:	recirculation
Total # Votes:	293
Total Ballot Pool:	313
Quorum:	**93.61 % The Quorum has been reached**
Weighted Segment Vote:	86.54 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	95	1	68	0.829	14	0.171	7	6
2 - Segment 2.	11	1	7	0.7	3	0.3	1	0
3 - Segment 3.	66	1	50	0.833	10	0.167	5	1
4 - Segment 4.	26	1	16	0.889	2	0.111	6	2
5 - Segment 5.	58	1	40	0.851	7	0.149	5	6
6 - Segment 6.	37	1	28	0.875	4	0.125	3	2
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.5	5	0.5	0	0	1	2
9 - Segment 9.	4	0.4	4	0.4	0	0	0	0
10 - Segment 10.	8	0.7	7	0.7	0	0	0	1
Totals	**313**	**7.6**	**225**	**6.577**	**40**	**1.023**	**28**	**20**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Affirmative	View
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	APS	Barbara McMinn	Affirmative	
1	Arizona Public Service Co.	Robert D Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Abstain	

1	Avista Corp.	Scott Kinney	Affirmative	View
1	BC Transmission Corporation	Gordon Rawlings	Negative	View
1	Beaches Energy Services	Joseph S. Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	CenterPoint Energy	Paul Rocha	Abstain	
1	Central Maine Power Company	Kevin L Howes	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Vero Beach	Randall McCamish	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Abstain	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	View
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker	Affirmative	View
1	Dominion Virginia Power	John K Loftis	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils		
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	GDS Associates, Inc.	Claudiu Cadar	Negative	
1	Georgia Transmission Corporation	Harold Taylor, II	Negative	View
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	View
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stan T. Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Lone Star Transmission, LLC	Julius Horvath	Affirmative	View
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	View
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	National Grid	Saurabh Saksena	Affirmative	
1	Nebraska Public Power District	Richard L. Koch	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Negative	View
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Utilities	David H. Boguslawski	Negative	View
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Douglas G Peterchuck	Affirmative	
1	Oncor Electric Delivery	Michael T. Quinn	Abstain	
1	Orlando Utilities Commission	Brad Chase	Negative	View
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	View
1	PacifiCorp	Colt Norrish	Affirmative	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	

1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Linda Brown	Negative	View
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Texas Electric Cooperative	Richard McLeon	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Negative	View
1	Southern Illinois Power Coop.	William G. Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	View
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young	Affirmative	View
1	Tennessee Valley Authority	Larry Akens	Negative	View
1	Tri-State G & T Association, Inc.	Keith V Carman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Negative	View
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	View
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Abstain	View
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	View
2	California ISO	Gregory Van Pelt	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Jason L Marshall	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Negative	View
2	New York Independent System Operator	Gregory Campoli	Affirmative	View
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Affirmative	View
3	Alabama Power Company	Richard J. Mandes	Negative	View
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris	Negative	View
3	Arkansas Electric Cooperative Corporation	Philip Huff	Abstain	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	Avista Corp.	Robert Lafferty	Affirmative	View
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	View
3	Black Hills Power	Andy Butcher	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	View
3	City of Leesburg	Phil Janik	Affirmative	
3	Cleco Corporation	Michelle A Corley	Abstain	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	View
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	Entergy	Joel T Plessinger	Abstain	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Negative	View
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Negative	
3	Hydro One Networks, Inc.	David L Kiguel	Affirmative	View
3	JEA	Garry Baker	Affirmative	

3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory David Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Negative	View
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	View
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	View
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	PacifiCorp	John Apperson	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young	Affirmative	
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey	Affirmative	View
3	Tennessee Valley Authority	Ian S Grant	Negative	View
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power - Ohio	Kevin Koloini	Abstain	
4	American Public Power Association	Allen Mosher	Affirmative	
4	Arkansas Electric Cooperative Corporation	Ronnie Frizzell	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Abstain	
4	City of Clewiston	Kevin McCarthy	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas W. Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Negative	
4	LaGen	Richard Comeaux		
4	Modesto Irrigation District	Spencer Tacke	Negative	View
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Oklahoma Municipal Power Authority	Terri Pyle	Abstain	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Tallahassee Electric	Allan Morales	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5		Edwin B Cano	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	APS	Mel Jensen	Negative	View
5	Avista Corp.	Edward F. Groce	Abstain	
5	BC Hydro and Power Authority	Clement Ma		

5	Black Hills Corp	George Tatar	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	City of Tallahassee	Alan Gale	Affirmative	
5	Cleco Power	Stephanie Huffman	Abstain	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	View
5	Consumers Energy	James B Lewis	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Electric Power Supply Association	Jack Cashin		
5	Energy Northwest - Columbia Generating Station	Doug Ramey	Affirmative	
5	Entergy Corporation	Stanley M Jaskot		
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	View
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	JEA	Donald Gilbert	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	Thomas J Trickey		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	View
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	View
5	New York Power Authority	Gerald Mannarino		
5	Northern California Power Agency	Tracy R Bibb	Abstain	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Pete Ungerman	Affirmative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	Jerzy A Slusarz	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	View
5	Tampa Electric Co.	RJames Rocha	Affirmative	View
5	Tenaska, Inc.	Scott M. Helyer	Negative	
5	Tennessee Valley Authority	George T. Ballew	Negative	View
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Abstain	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	View
6	Arizona Public Service Co.	Justin Thompson	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	View
6	City of Austin dba Austin Energy	Lisa L Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak	Abstain	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	View
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit		
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View

6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas E Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	View
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	View
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8		Roger C Zaklukiewicz		
8		James A Maenner	Affirmative	
8		Edward C Stein	Affirmative	
8	INTELLIBIND	Kevin Conway		
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Transmission Strategies, LLC	Bernie M Pasternack	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	View
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	Oregon Public Utility Commission	Jerome Murray	Affirmative	
9	Snohomish County PUD No. 1	William Moojen	Affirmative	
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	View
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool Regional Entity	Stacy Dochoda		
10	Texas Reliability Entity	Larry D Grimm	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	View

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2010-11 TPL Table 1, Footnote B
Recirculation Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

A recirculation ballot of Table 1 footnote 'b' in TPL-001-1 through TPL-004-1 ended on February 5, 2011. The standards were approved. Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 93.61 %
Approval: 86.54 %

Background:

FERC Order RM06-16-009 requires the ERO to clarify TPL-002-0, Table 1 - footnote 'b,' regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system, and originally directed NERC to file the revised standards by June 30, 2010. To meet this directive a proposed revision was posted for "Urgent Action" and balloted from May 17-27, 2010. The proposed revision achieved a quorum (84%) and almost enough affirmative votes (64%) to achieve weighted segment approval; however many balloters provided comments indicating the need for additional modifications. Following the initial ballot, FERC extended the due date to March 31, 2011, thus the project is no longer considered "Urgent Action."

Because Table 1 appears in TPL-001, TPL-002, TPL-003, and TPL-004, the change is reflected in all four standards:

- TPL-001-1 - System Performance Under Normal (No Contingency) Conditions (Category A)
- TPL-002-1b - System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- TPL-003-1a - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
- TPL-004-1 - System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

More details may be found on the project page:
http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Next Steps

The standards will go to the Board of Trustees for adoption.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.