NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

February 2, 2012

VIA ELECTRONIC FILING

David Erickson
President and Chief Executive Officer
Alberta Electric System Operator
2500, 330 - 5 Avenue SW
Calgary, Alberta
T2P 0L4

Re: *North American Electric Reliability Corporation*

Dear Mr. Erickson:

The North American Electric Reliability Corporation ("NERC") hereby submits this filing of one proposed revised Reliability Standard, the associated Violation Risk Factors and Violation Severity Levels, and five new definitions to be added to the NERC Glossary of Terms, as well as the retirement of four Reliability Standards and the withdrawal of two pending Reliability Standards. NERC also submits the attached implementation plan which establishes the schedule for implementing the proposed Reliability Standard.

NERC provides notice of the following revised Reliability Standard contained in **Exhibit A** to this petition: TPL-001-2 - Transmission System Planning Performance Requirements. NERC also provides notice of the proposed definitions of Bus-tie Breaker, Consequential Load Loss, Long-Term Transmission Planning Horizon, Non-Consequential Load Loss, and Planning Assessment.

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This submittal also includes a notice of retirement of four existing 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] ("BES") 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)

In addition, this submittal also withdraws two pending Reliability Standards:

- TPL-005-0 — Regional and Interregional Self-Assessment Reliability Reports
- TPL-006-0.1 – Data From the Regional Reliability Organization Needed to Assess Reliability

The proposed TPL-001-2 Reliability Standard addresses the important reliability goal of establishing transmission planning performance requirements for reliable Bulk Electric System ("BES") operations across normal and Contingency conditions. TPL-001-2 — Transmission System Planning Performance Requirements will serve as the foundational standard for annual planning assessments conducted by Planning Coordinators and Transmission Planners to plan the Bulk Electric System ("BES") reliably in response to a range of potential contingencies. The standard presents clear, measurable, and enforceable Requirements that each Planning Coordinator and Transmission Planner must follow when planning its System.

The proposed TPL-001-2 standard combines elements of the Reliability Standards TPL-001-1 — System Performance Under Normal (No Contingency) Conditions (Category A), TPL-002-1b — System Performance Following Loss of a Single BES 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. The proposed standard also incorporates and expands upon the revised Footnote “b” to Table 1 of the previous TPL group of standards. The requirements from TPL-005-0 — Regional and Interregional Self-Assessment Reliability Reports and TPL-006-0.1 — Data from the Regional Reliability Organization Needed to Assess Reliability have been moved to Sections 803 and 804 of the NERC Rules of Procedure.

In replacing these previous standards, TPL-001-2 introduces significant revisions and improvements including increased specificity of data requirements and modeling conditions. For example, sensitivity studies varying one or more modeling conditions by a sufficient amount to stress the system will be required. Annual assessments addressing Near-Term and Long-Term Planning Horizons for steady state, short circuit, and stability conditions must be conducted under the proposed standard. Planners will be required to address the impact of the unavailability of long lead-time critical equipment in a manner consistent with their entity's spare equipment strategy. The proposed standard clarifies how load loss may be utilized by transmission planners. Proper assessments conducted in accordance with the proposed standard will include an entity's criteria outlining acceptable voltage limits and deviations as well as the criteria used for analysis of instability. These assessments will then be distributed to other nearby entities for the purpose of facilitating a peer review so that entities may coordinate and improve their planning assessments across an Interconnection.

Proposed TPL-001-2 addresses twenty-seven Federal Energy Regulatory Commission ("FERC") directives issued in FERC Order No. 693 and subsequent orders as well as addressing numerous other concerns expressed by stakeholders, including the industry and FERC Staff, during the development of the standard. Twenty-four of the responses to FERC's directives directly adhere to the directives issued. The standard drafting team addressed an additional three directives by equally effective and efficient solutions as provided for in Order No. 693.[1]

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[1] *Mandatory Reliability Standards for the Bulk-Power* System, Order No. 693, FERC Stats. & Regs. ¶ 31,242 (2007), *order on reh'*g Order No. 693-A, 120 FERC ¶ 61,053 (2007)("Order No. 693") at P 31.

The proposed TPL-001-2 Reliability Standard serves the important reliability goal of ensuring that a Transmission System is planned to operate reliably under normal and Contingency conditions. Additionally, the proposed standard improves uniformity and transparency in the planning process and clarifies the instances where planners may utilize load loss.

The TPL-001-2 — Transmission System Planning Performance Requirements Reliability Standard was approved by the NERC Board of Trustees on August 4, 2011.

This notice consists of the following:

- This transmittal letter;
- A table of contents for the entire petition;
- A narrative description explaining how the proposed Reliability Standard TPL-001-2 — Transmission System Planning Performance Requirements meets reliability requirements;
- Reliability Standard TPL-001-2 — Transmission System Planning Performance Requirements (**Exhibit A**);
- Implementation Plan for Reliability Standard TPL-001-2 — Transmission System Planning Performance Requirements (**Exhibit B**);
- Violation Risk Factors and Violation Severity Levels analysis for TPL-001-2 (**Exhibit C**)
- Consideration of Comments Reports created during the development of Reliability Standard TPL-001-2 — Transmission System Planning Performance Requirements (**Exhibit D)**
- Mapping Document Explaining the transposition of requirements from previous TPL Reliability Standards to TPL-001-2 — Transmission System Planning Performance Requirements (**Exhibit E**);
- The complete development record of the proposed Reliability Standard (**Exhibit F**); and

- The Standard Drafting Team roster and biographical information for NERC Standards Development Project 2006-02 Assess Transmission Future Needs and Develop Transmission Plans (**Exhibit G**).

NERC understands the AESO may adopt the proposed standard subject to Alberta legislation, principally as established in the *Transmission Regulation* ("the T Reg."). Briefly, it is NERC's understanding that the T Reg. requires the following with regard to the adoption in Alberta of a NERC Reliability Standard:

1. The AESO must consult with those market participants that it considers are likely to be directly affected.

2. The AESO must forward the proposed reliability standards to the Alberta Utilities Commission for review, along with the AESO's recommendation that the Commission approve or reject them.

3. The Commission must follow the recommendation of the AESO that the Commission approve or reject the proposed reliability standards unless an interested person satisfies the Commission that the AESO's recommendation is "technically deficient" or "not in the public interest."

Further, NERC has been advised by the AESO that the AESO practice with respect to the adoption of a NERC Reliability Standard includes a review of the NERC Reliability Standard for applicability to Alberta legislation and electric industry practice. NERC has been advised that, while the objective is to adhere as closely as possible to the requirements of the NERC Reliability Standard, each NERC Reliability Standard approved in Alberta (called an "Alberta reliability standard") generally varies from the similar and related NERC Reliability Standard.

NERC requests the AESO consider the attached standard for adoption in Alberta as an "Alberta reliability standard(s)", subject to the required procedures and legislation of Alberta.

Respectfully submitted,

/s/ Andrew M. Dressel

Andrew M. Dressel
Attorney
North American Electric Reliability Corporation

BEFORE THE
ALBERTA ELECTRIC SYSTEM OPERATOR

NORTH AMERICAN ELECTRIC	**)**
RELIABILITY CORPORATION	**)**

NOTICE OF FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION OF A REVISED TRANSMISSION PLANNING SYSTEM PERFORMANCE REQUIREMENTS RELIABILITY STANDARD AND FIVE NEW GLOSSARY TERMS AND FOR RETIREMENT OF FOUR EXISTING RELIABLITY STANDARDS

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February 2, 2012

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Exhibit D — Consideration of Comments Reports created during the development of Reliability Standard TPL-001-2 — Transmission System Planning Performance Requirements

Exhibit E — Mapping Document Explaining the transposition of requirements from previous TPL Reliability Standards to TPL-001-2 — Transmission System Planning Performance Requirements

Exhibit F — The complete development record of the proposed Reliability Standard

Exhibit G — The Standard Drafting Team roster and biographical information for NERC Standards Development *Project 2006-02 Assess Transmission Future Needs and Develop Transmission Plans*

I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC") respectfully submits notice of one proposed revised Reliability Standard:TPL-001-2 — Transmission System Planning Performance Requirements, the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs"), and the implementation plan which establishes the schedule for implementing the proposed Reliability Standard. NERC is also retiring four existing Reliability Standards: (1) TPL-001-1 — System Performance Under Normal (No Contingency) Conditions (Category A), (2) TPL-002-1b — System Performance Following Loss of a Single [Bulk Electric System] ("BES") Element (Category B), (3) TPL-003-1a — System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), and (4) TPL-004-1 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D). Additionally, NERC is withdrawing two standards TPL-005-0 — Regional and Interregional Self-Assessment Reliability Reports, and TPL-006-0.1 – Data From the Regional Reliability Organization Needed to Assess Reliability.

The NERC Board of Trustees approved this proposed Reliability Standard on August 4, 2011. TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1 will be

> retired at midnight the day before TPL-001-2 becomes effective as the previous standards are replaced in their entirety by TPL-001-2. TPL-005-0 and TPL-006-0.1 are being retired at midnight the day before TPL-001-2 becomes effective because their requirements are adequately covered by the revised TPL-001-2 and NERC's Rules of Procedure, Section 800. However, during this 24-month period, all aspects of the latest enforceable versions of TPL-001 through TPL-006 shall remain in effect for compliance monitoring. This 24 month period is to allow entities to develop, perform or validate new or modified studies, methodologies, assessments, procedures, etc. necessary to implement and meet the TPL-001-2 requirements.[1]

Thus, all of the requirements of the previous TPL standards will remain in effect until all of the requirements in the proposed standard become effective.

[1] Implementation Plan for TPL-001-2, **Exhibit B,** *infra*.

Exhibit A to this filing sets forth the proposed Reliability Standard. **Exhibit B** to this filing is the Implementation Plan for Reliability Standard TPL-001-2 — Transmission System Planning Performance Requirements. **Exhibit C** is an analysis demonstrating that the proposed VRFs and VSLs for TPL-001-2 meet the VRF and VSL guidelines. **Exhibit D** contains the Matrix of FERC Directives and Industry Issues Considered in the development of this proposed standard. **Exhibit E** contains the Mapping Document which explains the transposition of requirements from previous TPL Reliability Standards to TPL-001-2 — Transmission System Planning Performance Requirements. **Exhibit F** is the complete development record of the proposed Reliability Standard. **Exhibit G** includes the standard drafting team ("SDT") roster and a short biography of each SDT member that developed the proposed Reliability Standard.

NERC submitted this filing with FERC, and is also filing this proposed Reliability Standard with the other 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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III. EXECUTIVE SUMMARY

The proposed TPL-001-2 Reliability Standard addresses the important reliability goal of establishing transmission planning performance requirements for the reliable planning of the Bulk Electric System ("BES") across normal and Contingency conditions. TPL-001-2 — Transmission System Planning Performance Requirements will serve as the foundational standard for annual planning assessments conducted by Planning Coordinators and Transmission Planners to plan the BES reliably in response to a range of potential contingencies. The standard presents clear, measurable, and enforceable Requirements that each Planning Coordinator and Transmission Planner must follow when planning its System.

The proposed TPL-001-2 combines elements of the Reliability Standards TPL-001-1 — System Performance Under Normal (No Contingency) Conditions (Category A), TPL-002-1b —

System Performance Following Loss of a Single BES 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.

In replacing the TPL-001-1 through TPL-004-1 standards, the proposed TPL-001-2 standard introduces significant revisions and improvements including increased specificity of data requirements and modeling conditions. The proposed standard also incorporates and expands upon the revised Footnote "b" to Table 1 of the previous TPL group of standards. Sensitivity studies varying one or more modeling conditions by a sufficient amount to stress the system will be required. Annual assessments addressing Near-Term and Long-Term Planning Horizons for steady state, short circuit, and stability conditions must be conducted under the proposed standard. Planners will be required to address the impact of the unavailability of long lead-time critical equipment in a manner consistent with their entity's spare equipment strategy. The proposed standard also provides limitations on the conditions under which planned load loss is permitted. Proper assessments conducted in accordance with the proposed standard will include an entity's criteria outlining acceptable voltage limits and deviations as well as the criteria used for analysis of instability. These assessments will then be distributed to affected entities for the purpose of facilitating a peer review so that entities may coordinate and improve their planning assessments across an Interconnection.

Proposed TPL-001-2 addresses twenty-seven FERC directives issued in FERC Order No. 693 and subsequent orders as well as addressing numerous other concerns expressed by stakeholders, including the industry and FERC Staff, during the development of the standard. Twenty-four of the responses to FERC's directives directly conform to the directives issued.

The standard drafting team addressed an additional three directives through equally effective and efficient solutions as permitted in FERC Order No. 693.[2]

Accordingly, the proposed TPL-001-2 Reliability Standard serves the important reliability goal of ensuring that a Transmission System is planned to operate reliably under normal and Contingency conditions. Additionally, the proposed standard improves uniformity and transparency in the planning process and clarifies the instances where planners may utilize load loss. This standard will achieve reliability performance beyond that achieved by the previous standards being replaced.

The proposed TPL-001-2 Reliability Standard was approved by a ballot pool that was conducted from July 13 to July 24, 2011. With a 94.33 percent quorum participating in the ballot, the proposed Reliability Standard achieved a weighted segment approval vote of 75.37 percent. The proposed Reliability Standard thus achieved the required two-thirds weighted segment vote and at least a 75 percent quorum of the ballot pool. The Transmission System Planning Performance Requirements Reliability Standard was approved by the NERC Board of Trustees on August 4, 2011.

IV. BACKGROUND

a. Basis for Proposed Changes to Reliability Standards

The proposed Reliability Standard, TPL-001-2 — Transmission System Planning Performance Requirements, is intended to ensure that a set of coordinated Planning Assessments are in place and that planners have engaged in system planning based on established performance criteria. The proposed standard will apply to Planning Coordinators and Transmission Planners.

[2] *Mandatory Reliability Standards for the Bulk-Power* System, Order No. 693, FERC Stats. & Regs. ¶ 31,242 (2007), *order on reh'*g Order No. 693-A, 120 FERC ¶ 61,053 (2007)("Order No. 693") at P 31.

The proposed standard represents a substantial revision yielding significant improvements relative to the current set of enforceable standards. This project advances the overall quality of the transmission planning ("TPL") standards group, eliminating gaps in the requirements, removing ambiguity, eliminating the "fill-in-the-blank" components, and addressing numerous FERC regulatory directives, as highlighted here and shown in **Exhibit D**.

Highlights of the improvements are that the proposed standard:

- Clarifies when loss of load may be utilized for Transmission Planning drawing distinctions between Consequential Load Loss and Non-Consequential Load Loss
- Provides a clear requirement for the Transmission Planner and Planning Coordinator to maintain System models for performing studies by requiring:
  - A direct linkage to the MOD-010-0 and MOD-012-0 Reliability Standards
  - That items from Corrective Action Plans need to be included in the models
  - That projected system conditions shall be represented
  - Specified list of items to be represented in the models
- Requires distribution of Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. Planning Assessments must also be distributed to other registered entities with a reliability-related need that submit a written request for the information. This will allow all of an applicable entity's peers to review Planning Assessments for events that will impact their System.
- Requires an annual Planning Assessment that:
  - Addresses both the Near-Term Transmission Planning Horizon and the Long-Term Transmission Planning Horizon
  - Requires steady state, short circuit, and stability analysis supported by required studies
- Requires that studies shall be based on:
  - A Contingency list for planning events and extreme events

    - Simulation of the removal of multiple elements where a protection system or other automatic control are expected to disconnect them for a Contingency
    - Tripping of elements that are expected to be disconnected because of voltage ride-through issues, relay loadability issues or transient swings

- Includes sensitivity studies varying one or more conditions by a sufficient amount to stress the system
- Addresses the need to plan for the unavailability of major equipment with a lead time of one year or more based on an entity's spare equipment strategy
- Qualifies when past studies may be used to support the Planning Assessment
- Requires the creation of System deficiencies lists and Corrective Action Plans when system analyses indicate an inability to meet performance requirements
- Requires criteria for acceptable System steady-state voltage limits, post-Contingency voltage deviations, and transient voltage response
- Requires registered entities to submit the criteria or methodology utilized to identify System instability
- Determines and identifies individual or joint responsibilities for the Planning Assessment
- Includes a complete revision of Table 1 to clearly articulate the contingencies that must be evaluated to ensure that the planned System meets the performance requirements. These changes include changing the classification of the events, clarifying events and Fault types, and removing the ambiguity of performance requirements.

- For extreme events, the revised Table 1 describes System performance for Wide Area events, including cyber attacks, and the standard clearly defines when further evaluation is required

NERC is also providing notice of five new definitions:

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

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.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

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.

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.

The proposed revisions consolidate requirements from four existing standards into one standard. Thus NERC is proposing to retire the following four Reliability Standards: (1) TPL-001-1 — System Performance Under Normal Conditions, (2)TPL-002-1b — System Performance Following Loss of a Single BES Element, (3) TPL-003-1a — System Performance Following Loss of Two or More BES Elements, and (4) TPL-004-1 — System Performance Following Extreme BES Events, because they are no longer needed. In addition, NERC is proposing to withdraw two Reliability Standards (1) TPL-005-0 — Regional and Interregional Self-Assessment Reliability Reports, and (2) TPL-006-0.1 — Data From the Regional Reliability Organization Needed to Assess Reliability in their entirety.

As shown in **Exhibit D** the changes in this proposed standard reflect consideration of a number of issues that were captured during NERC's original translation of former Operating Policies and Planning Standards to what are called the "Version 0" standards. Also considered were issues noted during the development of compliance measures for the Phase III and Phase IV Reliability Standards Project developed subsequent to Version 0 development, the development of Violation Risk Factors Project in 2006, Order No. 693, and subsequent FERC Orders.

b. Background of proposed Transmission Planning standard footnotes "9" and "12" to Table 1 and Previously Filed Version 1, Footnote "b"

On April 13, 2011, NERC submitted a Notice of Filing of Four Transmission Planning System Performance Reliability Standards and Retirement of Four Existing Reliability Standards ("March 31 Footnote B Filing") pursuant to FERC's March 18, 2010 Order Setting Deadline for Compliance on the TPL-002-0 standard[3] to comply with the directives in Order No. 693.[4] In the April 13 Footnote B Filing, NERC proposed a solution to FERC's directive from Order No. 693 that is as efficient and effective as the approach described in the directive. On May 17, 2011[5] FERC issued a data request to NERC requesting additional information on NERC's proposed Footnote b, and NERC responded to the data request on June 7, 2011.[6]

The proposed Footnote b of Table 1 for version 1 of the following transmission planning Reliability Standards is identical for each of the four standards:

- TPL-001-1 - System Performance Under Normal (No Contingency) Conditions (Category A), TPL-002-1b - System

[3] *Setting Deadline For Compliance*, 130 FERC ¶ 61,200 (2010).
[4] Order No. 693 at P 1773.
[5] Letter from the Commission seeking additional information from NERC regarding Reliability Standards TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1, Docket No. RM11-18-000 (May 17, 2011).
[6] *Response of the North American Electric Reliability Corporation to the Federal Energy Regulatory Commission's May 17, 2011 Letter Requesting Additional Information Regarding NERC's Request for Approval of Four Transmission Planning System Performance Reliability Standards*, Docket No. RM11-18-000 (June 7, 2011).

- 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)

Version 1 of these four transmission planning reliability standards was filed with with the April 13 Footnote B Filing.[7] Version 2 of the transmission planning reliability standard TPL-001-2, which is the standard proposed in this filing, replaces in their entirety the four version 1 transmission planning reliability standards identified immediately above. In creating TPL-001-2, the proposed Footnote b of Table 1 of version 1 of the transmission planning reliability standards ("Footnote b") was modified slightly and carried over as Steady State & Stability Performance Footnotes 9 and 12 ("Notes "9" and 12") in TPL-001-2.

Footnote b reads 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.

While proposed Note 9 reads as follows:

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[7] FERC issued a Notice of Proposed Rulemaking ("NOPR") on October 20, 2011 regarding the Footnote B filing. In the NOPR, FERC is proposing to remand to NERC its proposed modification to TPL-002-1, Table 1, footnote 'b' (version 1). FERC states in the NOPR that it believes that NERC's proposal does not meet the directives in Order No. 693 and does not clarify or define the circumstances in which an entity can plan to interrupt Firm Demand for a single contingency.

An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action 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 any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.

And Note 12 states:

An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to address BES performance requirements. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss is documented, including alternatives evaluated; and where the utilization of Non-Consequential Load Loss is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

Where Non-Consequential Load Loss is proposed to be defined in TPL-001-2 as: "Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment."

Proposed Notes 9 and 12 addresses the directives from Order No. 693, as clarified in FERC's June 11, 2010 order denying rehearing and granting partial clarification.[8] In FERC's June 11 Order, FERC did not strictly prohibit planning to shed firm Load in all circumstances. FERC stated:

21. [] the above passage from Order No. 693 acknowledged that the ERO could consider the comments of Entergy and Northern Indiana regarding planning for the loss of firm service "at the fringes of various systems," as NERC now characterizes the issue.[f.n. omitted] However, the Commission expressed concern that whatever approach is chosen by the ERO does not reflect a "lowest common denominator," i.e., "[t]he proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice – the so-called 'lowest common denominator' – if such practice does not adequately protect Bulk-Power System reliability." [f.n. omitted] Moreover, the Commission, in the same

[8] *Order Denying Rehearing and Granting Partial Clarification, Denying Request for Stay, and Granting Extension of Time*, 131 FERC ¶ 61,231 (2010)

> passage from Order No. 693, then provided a clarification that an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances. We believe that a regional difference, or a case-specific exception process that can be technically justified, to plan for the loss of firm service "at the fringes of various systems" would be an acceptable approach. Thus, the Commission did not dictate a single solution as NERC and others now claim. In any event, NERC must provide a strong technical justification for its proposal.[9]

NERC addressed FERC's instruction to clarify Footnote b regarding Load loss following a single contingency, specifying the amount and duration of load loss and system adjustments permitted after the first contingency to return the system to a normal operating state. 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." Rather, both Footnote b and Notes 9 and 12 meet FERC's objective while simultaneously meeting the needs of industry and respecting 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 meet the specified conditions detailed in the Footnote.

After extensive consideration during the standards development process of FERC's suggestion in Order No. 693 that NERC develop a case-specific exceptions procedure,[10] NERC, through the standards development process, chose a response that NERC believes is at least as efficient and effective as FERC's suggested process. As described in the March 31 Footnote B Filing, NERC believes that an ERO-sponsored planning process is not likely to be efficient or effective because of complex jurisdictional issues between NERC, FERC, and the many authorities having jurisdiction that would have to be resolved in perhaps forty-eight states and Canada, before implementation could occur. A NERC-centered process would at best duplicate

[9] *Id.* at P 21.
[10] Order No. 693 at P 1794.

planning actions going on elsewhere (where resource allocation decisions are actually being made), and such a process could lead to inconsistent results. It appeared to the industry and to NERC that a more reasonable and expeditious path would be to rely on existing stakeholder processes, many of which are driven by other FERC orders. Such processes would be more likely to engage the appropriate local-level decision-makers and policy-makers. For these reasons, NERC's March 31 Footnote B Filing proposed an efficient and effective alternative in responding to the directive and implementing Footnote b planned outages by leveraging current, existing stakeholder processes already established to address transmission planning choices. The same rationale applies to Notes 9 and12 as well.

FERC already mandates transmission planning processes through specific requirements addressed in Order No. 890 and subsequent orders. Order No. 890 reformed the *pro forma* Open Access Transmission Tariff to require each public utility transmission provider to have a coordinated, open, and transparent regional transmission planning process. FERC's recent Order No. 1000 builds upon Order No. 890 by broadening participation in regional transmission planning processes.[11] Specifically, Order No. 1000 requires that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan.[12]

FERC's Order No. 1000 bolsters FERC-mandated transmission planning processes by broadening participation in stakeholder processes. FERC enhanced transmission planning requirements by finding that "it is necessary to have an affirmative obligation in these transmission planning regions to evaluate alternatives that may meet the needs of the region

[11] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 136 FERC ¶ 61,051, Order No. 1000 (2011) at P 1, 3, Sec. III. ("Order No. 1000").
[12] *Id.* at P 80

more efficiently or cost-effectively."[13] FERC stated that "In the absence of the reforms implemented below, we are concerned that public utility transmission providers may not adequately assess the potential benefits of alternative transmission solutions at the regional level that may meet the needs of a transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in their local transmission planning process."[14]

Additionally, Order No. 1000 provides a mechanism for Regional Entity engagement and broadens the scope to include public policy considerations. FERC's reinforcement of stakeholder processes in Order No. 1000 avoids the competing jurisdictional concerns that could result from a new process created exclusively for the purpose of assuring reliability.

The planning principles articulated by FERC in Order No. 1000 reinforces NERC's position presented in the March 31, 2011 Footnote b filing, NERC's June 17, 2011 response to the data request, and reiterated in this Notice of Filing of the proposed TPL-001-2 standard. Specifically, FERC, through Order No. 1000, is promoting a stakeholder process that includes: coordination; openness; transparency; information exchange; comparability; dispute resolution; and economic planning studies.

Accordingly, relying on existing stakeholder processes to implement Footnote b and Note 9, including stakeholder processes developed under FERC Order Nos. 890 and 1000, will provide mechanisms for NERC and the Regional Entities to effectively monitor an entity's planned interruptions of Firm Transmission Service by making these planned interruptions visible. Proposed Note 9 recognizes that it is generally inappropriate to plan to interrupt Firm Transmission Service to meet reliability performance metrics. However, in limited

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[13] *Id.*.
[14] *Id.* at P 81.

circumstances, an entity may rely on planned Load shedding. The magnitude and timeframe for which the entity plans to rely on Load shedding will be limited to circumstances where its use is documented and subject to an open and transparent stakeholder process.

The language in Note 12 of the proposed TPL-001-2 standard specifically provides that: "[w]hen Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss is documented, including alternatives evaluated; and where the utilization of Non-Consequential Load Loss is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments." In other words, the language in Note 12 specifically provides for a review of how the Non-Consequential Load Loss was determined, whether any alternatives were evaluated, and how the determination to plan to shed Non-Consequential Load Loss was made through an open and transparent stakeholder process.

In an audit or spot check of an entity, one of the first questions asked will be whether the entity planned on interrupting Firm Demand to meet reliability performance requirements. If so, the entity will be required to provide all relevant documents pertaining to such transmission planning decisions, including any documentation used to make such a determination through an open and transparent stakeholder process. This documentation should include the specifics of what Load will be shed and under what circumstances. The entity will also be required to provide a description of other alternatives the entity considered and a description of the stakeholder process in which the decision to rely on Load shedding was made. Additionally, the audit or spot check will include a discussion of the activity or participation by the relevant governmental authority with jurisdiction over the matter. Based on all of this information, NERC or the Regional Entities will be able to determine whether the decision by the entity to rely on Load shedding to meet performance requirements was reasonable given the circumstances.

Accordingly, for the reasons stated in NERC's April 13 Footnote B Filing, NERC's June 17, 2011 response to FERC's data request, and in this notice, the approach proposed in Notes 9 and 12 presents an equally efficient and effective alternative to responding to FERC's Order No. 693 directive because many of the stakeholder processes that will be used in planning decisions are already in place, as implemented by FERC in Order No. 890 and in state regulatory jurisdictions, or will be in place, pursuant to FERC's Order No. 1000. More localized decision-making is preferable to an ERO-centric exceptions process because of the inevitable debate about cost which is implicit in planning decisions. Additionally, the approach is effective because the ERO process will be able to monitor any planned use of Notes 9 and 12 through audits of the transmission planners. These audits will ensure that the use of Notes 9 and 12 is being addressed under the open and transparent guidelines established there. For these reasons, the approach presented in Notes 9 and 12 fulfills the FERC directive in an equally efficient and effective manner, and is achievable in a reasonably short time frame having gained the acceptance of the industry. Proposed Notes 9 and 12 raises the bar because it now requires full documentation and disclosure of planning choices impacting reliability.

V. <u>REGULATORY DIRECTIVES</u>

The SDT addressed twenty-seven directives issued by FERC in Order No. 693.[15] These directives are presented below with resolutions proposed by the SDT. The text of the complete proposed standard TPL-001-2— Transmission System Planning Performance Requirements is

[15] *Mandatory Reliability Standards for the Bulk-Power* System, Order No. 693, FERC Stats. & Regs. ¶ 31,242 (2007), *order on reh'*g Order No. 693-A, 120 FERC ¶ 61,053 (2007)("Order No. 693").

included in **Exhibit A**. These resolutions are summarized in **Exhibit D** along with the resolutions to industry concerns.

1. Paragraph 1691(of Order No. 693) - Ensure that the planning requirements are specific enough to promote rigor and consistency in assessments and provide clear and measurable rules for mandatory and enforceable Reliability Standards.
    - SDT resolution: The SDT directly addressed the specifics of this directive. The proposed standard strikes a balance between rigidity for specific requirements (for example, Table 1 event descriptions and performance requirements) and flexibility where individual system concerns are best served through engineering judgment (for example, Requirement R2, Parts 2.1.4 & 2.4.3 list the factors and sensitivities that should be addressed to stress the System). The proposed Reliability Standard ensures that the planning process and the BES are robust enough to be able to withstand a range of probable contingencies while reliably serving customer demand and preventing identified outages. Conversely the standard is flexible enough to accommodate a broad range of system conditions over a planning horizon to account for the lead times needed to place facilities in service. This will promote rigor and consistency in assessments and provide clear and measurable rules for mandatory and enforceable standards.
2. Paragraph 1691 - The planning standards should require planning entities to consider the probable range of contingencies when determining critical system conditions but only those deemed to be significant need to be assessed with the documentation provided that explain the rationale for selection. Additionally, FERC stated "that it

would be appropriate for planning entities to conduct sensitivity studies to 'bracket' the range of probable outcomes."[16]

- SDT resolution: The SDT has directly adopted the specifics of this suggestion. In the proposed TPL-001-2, Requirement R2, Part 2.1 mandates the types of sensitivity studies that must be run. Building upon Requirement R2, Requirement R3 demands that an entity must perform Planning Assessments that meet system performance criteria for steady-state conditions. Requirement R3, Part 3.1 requires analysis of those contingencies that may cause the most severe system impact as determined in Requirement R3, Part 3.4. A similar expectation is found in Requirement R4 for stability studies in Parts 4.1 and 4.4.

3. Paragraph 1692 - Consider integrating TPL-001 through TPL-004 into a single Reliability Standard.
    - SDT resolution: The SDT directly adopted this directive. The proposed TPL-001-2 incorporates TPL-001-1 through TPL-004-1.
4. Paragraph 1693 - Submit an informational filing, in addition to regional criteria, addressing all utility and RTO/ISO differences in transmission planning criteria that are more stringent than those specified by the TPL group of Reliability Standards.
    - SDT resolution: The data was collected and filed by the ERO and distributed to the SDT. The SDT reviewed the compiled information and found that the majority of the planning practices identified in the survey were based on local conditions and not applicable to a continent-wide standard. However, one

[16] Order 693 at P 1694.

common practice, a generation outage coupled with another single Contingency without load loss treated as a single Contingency, was adopted by the SDT as part of planning category P3 (loss of generator unit followed by System adjustments ((g-1)+(n-1)) in Table 1.

5. Paragraph 1716 - System performance should be assessed based on single contingencies that faithfully duplicate what will happen in the actual power system.
    - SDT resolution: The SDT directly adopted the specifics of this directive in Requirement R3, Part 3.3.1 and Requirement R4, Part 4.4.1 of the proposed standard.
6. Paragraph 1716 - Entities that have planned and designed their systems on the basis of a different approach to single contingencies based on the existing standards should work with NERC in developing plans to transition to this new approach.
    - SDT resolution: The SDT directly addressed this directive. The SDT considered this issue and determined that a phased implementation approach to this proposed standard will allow entities to transition to the new or changed requirements in this proposed standard. Consequently, a phased implementation plan has been proposed.
7. Paragraph 1719 - Consider appropriate revisions to the Reliability Standards to address cyber security events. The system impacts of cyber security events are best addressed in the TPL group of Reliability Standards, particularly TPL-004-0 (extreme events).

- SDT resolution: The SDT has addressed this directive by adding Cyber security events to the list of steady state Wide Area extreme events in Table 1, Steady State, 3.a.v, in proposed TPL-001-2.

8. Paragraph 1755 - Require a peer review of planning assessments with neighboring entities.

   - SDT resolution: The SDT developed an equally effective and efficient manner to provide for the appropriate sharing of information with neighboring systems. This is covered in proposed TPL-001-2, Requirement R3, Part 3.4.1, Requirement R4, part 4.4.1, and Requirement R8.
   - Requirement R8 addresses the appropriate sharing of information with neighboring systems. The SDT believes that requiring applicable entities to distribute to adjacent Planning Coordinators and Transmission Planners is a better approach than a "peer review" approach, as an entity may always decline an offer to participate in a peer review even when they should participate. The distribution approach means that the entity will always receive the Planning Assessment. Requirement R8 ensures that information is shared in a timely manner[17] with those affected and input from those systems is received, without dictating how the two-way sharing must take place. In the course of the continuing cycle of Planning Assessments, comments from other entities at the end of a planning cycle will be utilized at the beginning of the next cycle as the planner moves forward in time. This approach does not dictate how information is shared but still makes certain that the goal is

[17] Requirement R8 requires distribution to adjacent Planning Coordinators and Transmission Planners within 90 days and to others with a reliability related need that submits a request within 30 days of receiving such a request.

achieved. This is an equally effective and efficient approach to the directive in Order No. 693.

- To cover those entities that may not be adjacent, the proposed standard requires the Transmission Planner and Planning Coordinator to distribute the Planning Assessment to additional entities that exhibit a "reliability-related need," who have requested information in writing, and require a documented response to their comments. This is an equally, effective and efficient manner to provide for the appropriate sharing of information with neighboring systems.
- Requirement R3, Part 3.4.1 and Requirement R4, Part 4.4.1 address the concern expressed by FERC regarding sharing information and coordinating responses to system contingencies that may affect adjacent[18] Systems.

9. Paragraph 1759 - Modify Requirement R1.3 to substitute the reference to Regional Reliability Organization with Regional Entity.
    - SDT resolution: The SDT directly adopted the specifics of this directive. All references to the Regional Reliability Organization have been removed. Furthermore, all new and future revisions to all NERC Reliability Standards will use the term Regional Entity instead of the previous term Regional Reliability Organization.
10. Paragraph 1765 - Determine critical system conditions and study years by conducting sensitivity analysis with due consideration of the factors outlined by FERC.

[18] Although Order No. 693 uses the term "neighboring" the proposed Reliability Standard uses "adjacent." "Adjacent" better clarifies the intent of the requirement to cover transmission systems that interconnect with the entity's System whereas "neighbor" is vague and could include systems in the vicinity of an entity's system, but not directly connected.

- SDT resolution: The SDT directly addressed the specifics of this directive. This is covered in proposed TPL-001-2, Requirement R2, Part 2.1.4 for steady state and Requirement R2, Part 2.4.3 for stability analyses. Inclusion of sensitivity analyses represent an important improvement to the proposed planning standard aimed at better understanding a range of probable outcomes of potential system conditions. Proposed TPL-001-2, Requirement R1 requires the System model to represent projected System conditions. Specifically, the proposed Reliability Standard requires planners to assess the potential impact of one or more changes to these assumed conditions which stress the system. The results of the sensitivity analyses help the planner develop a portfolio of information by identifying performance issues related to credible assumptions. This information is valuable to the planner to identify which set of assumptions have the most severe impacts on the performance of the planned system. Because the end of one planning cycle is the beginning of the next planning cycle, the results of the sensitivity studies will be available to the planner as they develop the following year's projected System conditions and to direct additional sensitivity analysis in future assessments.

11. Paragraph 1769 - Address concerns with footnote (a) of Table 1 with regard to applicability of emergency ratings and consistency of normal ratings and voltages with values obtained from other reliability standards.

    - SDT resolution: The SDT directly addressed the specifics of this directive. Proposed TPL-001-2, Requirement R3, Part 3.1 requires that studies shall be performed for planning events to determine that the BES meets the performance requirements in Table 1. Table 1, header notes 'e' and 'f' are part of the performance requirements of Table 1. Header note 'e' states that planned system adjustments must be executable within the time duration applicable to the facility ratings. Header note 'f states that applicable facility ratings shall not be exceeded.

12. Paragraph 1773 – Submit a modification to Footnote (b) that clarifies that firm load shedding or curtailment of firm transfers is not allowed as part of the system adjustments.

    - SDT resolution: NERC addressed this directive in *Project 2010-11 TPL Table 1* and its subsequent petition requesting approval of four TPL standards submitted March 31, 2011.[19] The SDT has transferred that solution to the proposed TPL-001-2 as footnotes 9 and 12 in Table 1.

13. Paragraph 1786 - Require assessments of planned outages of critical long lead-time equipment, consistent with an entity's spare equipment strategy.

    - SDT resolution: The SDT directly adopted the specifics of this directive. This is covered in proposed TPL-001-2, Requirement R2, Part 2.1.5. The proposed requirement addresses steady state conditions to determine system response when equipment is unavailable for prolonged periods of time. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 under the conditions that the system is expected to experience during the possible periods of unavailability of the long lead-time equipment. Stability

[19] *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*, Docket No. RM11-18-000 (March 31, 2011) ("March 31 Petition").

impacts related to outages of critical long lead-time equipment will not be addressed in a separate requirement but rather will be analyzed in the normal planning process in the evaluation of multiple Contingency events. Additionally, any known equipment outages of six months or more must be included in the modeled system in proposed TPL-001-2, Requirement R1.

14. Paragraph 1787 - Requires all generators to ride through the same set of Category B and C contingencies, as required by wind generators in Order No. 661, or to simulate those generators without this capability as tripping during modeling.
    - SDT resolution: The SDT directly adopted the specifics of this directive in proposed TPL-001-2, Requirement R3, Part 3.3.1.1 and Requirement R4, Part 4.3.1.1. No distinctions are made among different generation resources in the proposed Requirements.
15. Paragraph 1788 - Consider comments clarifying that for operations purposes clarifying that the N-1 state is always analyzed from the conditions being experienced.
    - SDT resolution: The SDT considered the comments and agrees with the Commission that these conditions are real-time oriented and not part of a planning process. N-1 conditions are studied as part of planning events P1 and P2 in the proposed TPL-001-2, Table 1.
16. Paragraph 1789 - Document the load models used in system studies and the supporting rationale for their use.

- SDT resolution: The SDT directly addressed the specifics of this directive in proposed TPL-001-2, Requirement R2 which requires entities to document assumptions made in their Planning Assessments.

17. Paragraph 1790 - Clarify the phrase “permit operating steps necessary to maintain system control” in footnote (a) to clarify the use of emergency ratings.
    - SDT resolution: The SDT directly addressed the specifics of this directive. Proposed TPL-001-2, Requirement R3, Part 3.1 requires performing studies for planning events to determine whether the BES meets the performance requirements in Table 1. Additionally, Table 1, header notes ‘e’ and ‘f,’ that are a part of the performance requirements of Table 1, demand more details. Header note ‘e’ states that planned system adjustments must be executable within the time duration applicable to the facility ratings. Header note ‘f states that applicable facility ratings shall not be exceeded.
18. Paragraph 1794 – The standard should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency. The standard should be clarified accordingly.
    - SDT resolution: This directive was addressed in *Project 2010-11 TPL Table 1* and the SDT has transferred that solution to the proposed TPL-001-2 as footnotes 9 and 12 in Table 1.
19. Paragraph 1795 - Consider developing a ceiling on the amount and duration of consequential load loss that will be acceptable.
    - SDT resolution: The directive was to “consider” the need for a ceiling on load and duration and if “appropriate” to develop the ceiling through the standards

development process. The SDT originally included requirements covering the reporting of the magnitude and duration of Consequential Load Loss. Industry overwhelming protested the inclusion of these requirements which were panned as additional administrative tasks that did not address any reliability need. Initial comments submitted by industry focused more on the topic of duration than magnitude so the SDT attempted to craft a compromise position. The duration element of the requirement was deleted and a revised requirement covering only magnitude of Consequential Load Loss was crafted and posted for comment.

- The SDT was again overwhelmed by negative industry comments pushing back about the inclusion of an administrative task without a reliability need in a Reliability Standard. At that point, the SDT discussed the matter at length, determined they agreed with the industry comments, and decided to delete the requirement in its entirety. The SDT addressed the directive to "consider developing a ceiling" as directed in Order No. 693 as evidenced in meeting notes and by its attempt to include the requirements for an equally effective method in the proposed Reliability Standard. Therefore, the SDT considers that it has fulfilled its obligation in this regard.

20. Paragraph 1796 - Clarify footnote (b) in regard to load loss following a single contingency to specify the amount and duration of consequential load loss and what types of system adjustments are permitted after the first contingency to return the system to a normal operating state, provided these adjustments can be accomplished within the time period allowed by the short term or emergency ratings.

- SDT resolution: NERC addressed this directive in *Project 2010-11 TPL Table 1*, the April 13 filing, and the SDT has addressed a solution to the proposed TPL-001-2 in footnotes 9 and 12 in Table 1.

21. Paragraph 1818 - Clarify the term "controlled load interruption".
    - SDT resolution: The term "controlled load interruption" is not included in the proposed TPL-001-2 Reliability Standard.
22. Paragraph 1820 - The Reliability Standard must define and document the proxies necessary to simulate cascading outages.
    - SDT resolution: The SDT directly adopted the specifics of this directive. This is covered in proposed TPL-001-2 in Requirement R6. This requirement mandates that the entity must define and document its criteria or methodology (proxies) used in its analysis.
23. Paragraph 1821, 1835 - Tailor the purpose statement to reflect the specific goal of the standard.
    - SDT resolution: The SDT directly adopted the specifics of this directive. The purpose statement of proposed TPL-001-2 has been rewritten to reflect the specific goal of the proposed standard.
24. Paragraph 1822 - Address Nuclear Regulatory Commission ("NRC") concerns as described in TPL-003 through the standards development process.
    - SDT resolution: The SDT considered the comments and agrees with the Commission that the NRC's concerns involve real-time issues and not the

planning process. N-1 conditions are studied as part of planning events P1 and P2 in the proposed TPL-001-2, Table 1.[20]

25. Paragraph 1833 - Identify options for reducing the probability or impacts of extreme events that cause cascading.

    - SDT resolution: The SDT directly addressed the specifics of this directive. This is covered in proposed TPL-001-2, Requirement R3, Part 3.5 & Requirement R4, Part 4.5. The requirements state that if an analysis concludes cascading will be caused by the occurrence of certain extreme events, applicable entities shall conduct an evaluation of possible actions designed to reduce the likelihood of those events from occurring or mitigate the consequences and adverse impacts of the event.

26. Paragraph 1836 - Expand the list of category D events to include recent actual events.

    - SDT resolution: The SDT has directly adopted the specifics of this directive. The list of Table 1 Steady State and Stability Extreme Events has been expanded to include wide-area events in extreme events 3b (steady state) and 2f (stability).

27. Paragraph 1841 - Utilize input from FERC's technical conferences on regional planning as directed in Order No. 890 into the Reliability Standards development process to improve this standard.

    - SDT resolution: The SDT directly adopted the specifics of this directive. The SDT utilized knowledge gained from FERC's technical conferences and added Requirement R8 to proposed TPL-001-2 to facilitate the distribution of

[20] *See* 14 above addressing P 1788.

planning results and to provide a mechanism for obtaining input from various entities. Additionally, TPL-001-2 will complement FERC's ongoing transmission planning efforts set forth in Order Nos. 890 and 1000.

In addition to addressing the FERC directives, the SDT has incorporated many other clarifications, improvements, and enhancements to the existing standards as outlined below:

- In Footnote 461 of Order No. 693, FERC stated "Consequential load is the load that is directly served by the elements that are removed from service as a result of the Contingency." The proposed definition for Consequential Load Loss in the proposed Reliability Standard states, "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." The proposed definition parallels the language required for Contingency analyses mandated in the proposed TPL-001-2, Requirement R3, Part 3.3.1 and Requirement R4, Part 4.3.1.
    - In addition to the definition of Consequential Load Loss, the SDT determined that a corresponding definition for Non-Consequential Load Loss was necessary to adequately describe how a planner may consider planned load loss for specific events. These events are described in Table 1 of the proposed TPL-001-2. In the proposed standard, Non-Consequential Load Loss is defined as:

> Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Importantly, this clarifies that interruptible load, *i.e.* load that is under contract or agreement for curtailment, is not Non-Consequential Load. Additionally, the definition clarified that "the response of voltage sensitive Load" or "Load that is disconnected from the System by end-user equipment" are not Non-Consequential Load. The SDT determined that the planner cannot control the sensitivity of load to voltage excursions or whether load may be disconnected by end-user equipment under certain conditions. The planner may have a valid plan that may include load loss that the planner cannot control because of one or both of these situations. The planner should not be held accountable for those situations. Consequently, the planner should not depend on this load loss to meet the performance requirements. Therefore, the SDT added Head Note "i" to Table 1 – Steady State & Stability Performance Planning Events, to ensure that the planned system can meet performance requirements while serving the load, including the voltage sensitive load. Head note "i" states that "The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements."

- The Implementation Plan consists of three effective dates – 12 months, 24 months, and 84 months following regulatory approval – that provides industry the time needed to transition to new reliability expectations.
    - Two of the eight reliability requirements (Requirements R1 and R7) of proposed standard TPL-001-2 are proposed to become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval.

    - In Requirement R1, the Transmission Planner and Planning Coordinator must develop and maintain system simulation models representing projected system conditions.
    - In Requirement R7, the Transmission Planner and Planning Coordinator will work together to identify each entity's individual and joint responsibilities for completing the required planning studies associated with the standard. The 12 month period is necessary to allow planners sufficient time to meet these new, more detailed modeling and coordination requirements.
- The remaining requirements of the standard – Requirements R2 through R6 and R8 – are proposed to be effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval (except for certain performance requirements stated in Table 1 that represent a significant change for industry related to planning of the BES transmission system). This 24 month period is needed to allow the applicable entities to develop, perform, and validate new or modified studies, methodologies, assessments, and procedures to implement and meet the proposed requirements in TPL-001-2. The effective date allows sufficient time for proper assessment of the available options necessary to create a viable Corrective Action Plan compliant with the proposed TPL-001-2.
- An extended implementation period beyond the 24 month milestone is permitted for situations where loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain planning events. In such

cases, the proposed TPL-001-2 allows an additional 60 months because Corrective Action Plans created by the Transmission Planner and Planning Coordinator may have significant budget, siting, permitting, and construction impacts on many Transmission Owners and developers. During the extended 60 month transition period, the Transmission Planner and Planning Coordinator may continue to rely on Non-Consequential Load Loss and interruption of firm transfers within its submitted Corrective Action Plan related to the select planning events.

    - As stated in the implementation plan (**Exhibit B)**, for 84 months beginning the first calendar day of the first calendar quarter following approval, Corrective Action Plans applying to certain categories of Contingencies and events identified in TPL-001-2, Table 1 will be allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service that would not otherwise be permitted by the requirements of TPL-001-2.

- Requirement R1
    - Requirement R1 of the proposed TPL-001-2 explicitly requires the Transmission Planner and Planning Coordinator to maintain System models. This represents an improvement over the existing TPL standards where the requirement to maintain the model was only implied, not explicitly required.
    - The proposed TPL-001-2 also provides a specific list of items required for the System models in Requirement R1, Part 1.1. The proposed TPL-001-2 links the models to the data provided in accordance with MOD-010-0 and MOD-012-0 to ensure that the planner utilizes data that is consistent with the data

provided to the planner but still allows the data to be supplemented by data from other sources as needed. The proposed TPL-001-2, Requirement R1 also incorporates Requirement R1.4 from the existing TPL standard by including items represented in the Corrective Action Plan.

- Requirement R1 also requires that the System models represent projected System conditions. The planner is required to model the items that are variable, such as load and generation dispatch, based specifically on the expected system conditions. For example, for a 60% load level study, the planner should model the load at 60% of the peak value and the generation that is expected to be operating at that load level. Therefore, generation with low run times, such as combustion turbines, would not be utilized for this load level, unless the planner had specific knowledge that they would be expected to operate for this load level.
- Requirement R1, Part 1.1.2 mandates that the System models "shall represent … known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months." Requirement R1.3 of the existing TPL-001-1 standard states, "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)." Requirement R1.3.12 of the existing TPL-002-0b standard addresses planned (including maintenance outages) and is one of the following categories referenced in Requirement R1.3. Therefore, in the existing TPL-002-0b standard, the specific elements selected to be evaluated as a part of Requirement R1.3.12 were selected by the

Transmission Planner or Planning Coordinator and must be acceptable to the associated Regional Reliability Organization. The SDT determined that having the planner select specific planned outages to include in their studies was not the appropriate manner to address this issue. Furthermore, the Regional Entities should not have the role of determining the appropriateness for inclusion or exclusion of specific planned outages in the studies in today's regulatory framework. Therefore, the SDT adopted a bright-line test to determine whether an outage should be included in the system models.

- The SDT determined that the appropriate manner to address planned outages, including maintenance outages, in the planning horizon begins with determining what length of outages could readily be scheduled without impacting BES reliability at peak load conditions. The SDT determined that, in the planning horizon, a six-month or longer outage duration would necessarily extend over a seasonal peak load period and should be included in the planning models. Requirement R1.3.12 of the existing standard included Protection Systems or their components in the items that could be selected by the planner. However, since Protection System maintenance or other outages are not ever anticipated to last six months, this language was not included in the proposed standard. The language in proposed TPL-001-2, R1, Part 1.1.2 removes the ambiguity of what the planner needs to include in the specific studies and requires the planner to evaluate all of the six-month or longer duration outages within its system. These outages are the significant outages that need to be evaluated in the planning horizon to ensure that the outages can be accommodated and still meet performance requirements.

- Requirement R2
    - To further enhance the evaluation of known outages, the SDT added Requirement R2, Part 2.1.3 that requires the planner to assess system performance utilizing a current annual study or qualified past study for each known outage with a duration of at least six months for Table 1, P1 events. This requirement ensures planners evaluate every known outage with known duration of six months or more, even if the known outage is not within one of the study years selected by the planner as required by the proposed Requirement R2, Part 2.1.1 or 2.1.2.
    - The existing TPL standards refer to valid assessments, but ambiguity exists regarding what constitutes a valid assessment leading to inconsistency. Subjectivity that was allowed before is now replaced with specifics. The requirements and parts of proposed TPL-001-2 leave no doubt as to what a valid study must entail, timeframes for use of past studies, minimum conditions (years and peak/off-peak conditions), what needs to be included in the model, and what performance must be achieved.
    - The proposed TPL-001-2 Requirement R2 mandates that short-circuit studies must be included in the assessment. Short-circuit studies were not included in the existing TPL standards. Short-circuit studies ensure that when a planner is considering System improvements that the interrupting capability of the breakers is addressed. Therefore, the inclusion of short-circuit studies

represents a significant improvement in the proposed TPL-001-2 over the prior TPL standards.

- The proposed TPL-001-2 clarifies that qualified past studies can be utilized in the analysis while tightly defining the qualifications for those studies. Currently, there are no limits on the use of past studies in the existing TPL standards. The use of qualified past studies allows an entity to continue to use validated studies to complete its assessment. This allows computational efficiency, maintains the legitimacy of the studies, and allows the planner to better utilize limited resources.
- The proposed TPL-001-2 standard provides greater clarity for near-term planning horizon steady-state and stability studies. The existing TPL standards are vague and open to entity discretion regarding the studies to be performed. Proposed TPL-001-2, Requirement R2, Parts 2.1 and 2.4 now explicitly require both peak and off-peak studies for both steady-state and stability. This change provides the industry greater clarity over the existing standard.
- The SDT has introduced sensitivity analyses to be completed as part of a Planning Assessment in proposed TPL-001-2, Requirement R2, Part 2.1.4 (for steady state) and Requirement R2, Part 2.4.3 (for stability). Conducting a sensitivity analysis is an important improvement to the proposed standard that will improve planners' understanding of the range of probable outcomes of potential system conditions. Sensitivity analyses demand that planners assess the potential impact of one or more changes in the assumed System conditions

to stress the System. The results of the sensitivity studies help planners develop a portfolio of information by identifying potential performance issues related to credible assumptions. This information is valuable to the planner to identify which set of assumptions have the most severe impact on the performance of the planned system. Because the end of one planning cycle is the beginning of the next planning cycle, the results of the previous sensitivity studies will be available to the planners when they develop their System's projected conditions and also for directing additional sensitivity analysis in the following year's assessment. Furthermore, the proposed Requirement R2, Part 2.7.2 addresses the issue of how to address performance deficiencies identified in multiple sensitivity studies. This represents a significant improvement in the planning process.

- An entity's spare equipment strategy is addressed in proposed Requirement 2.1.5 by requiring that entities account for equipment that will be unavailable for prolonged periods of time when determining the system response for steady state conditions. Studies shall be performed for the P0, P1, and P2 categories identified in Table 1 under the conditions a System can be expected to experience during the possible unavailability of critical long lead-time equipment. Stability impacts related to critical outages of long lead-time equipment are not included as a separate requirement because they are required to be analyzed in the normal planning process by evaluating multiple Contingency events. Any known equipment outages of six months or more must be included in the modeled system as shown in proposed TPL-001-2, Requirement R1. This condition was not included in the existing TPL standards, which created a reliability gap that will now be filled.

- Proposed Requirement R2, Part 2.2 offers a significant improvement over the existing TPL standards by requiring an annual "fresh" or "current year" steady-state study for the long-term planning horizon. During the standard development process, the SDT responded to industry comments and indicated that the requirement to conduct a current annual study for one of the study years in the long-term transmission planning horizon will enable earlier identification of potential transmission performance limitations and earlier development of Corrective Action Plans. These study results may then be used as qualified past studies in later years.
- The proposed TPL-001-2 includes a new requirement, Requirement R2, Part 2.7.3 that allows Transmission Planners and Planning Coordinators to utilize Non-Consequential Load Loss to meet performance requirements if the applicable entities are unable to complete a Corrective Action Plan due to circumstances beyond their control. This requirement is necessitated by the improvements within the proposed TPL-001-2 that do not allow the Loss of Non-Consequential Load where it was previously allowed in the existing TPL standards, *e.g.*, planning event P2-3 for EHV. Historically, the planners could have planned for controlled interruption of demand for this event. That option is no longer available under the proposed TPL-001-2. Without proposed Requirement R2, Part 2.7.3, a planner may develop a valid Corrective Action Plan that resolves an issue and begin work on the plan with a realistic

expectation to complete the plan six months before the required in-service date. However, actions beyond the control of the planner may derail that plan and make the Corrective Action Plan no longer viable. Some examples of situations beyond the control of the planner could include a state road-widening project taking substation land that was targeted for expansion or a ruling preventing the entity from condemning the land necessary for a project. For these situations, planners need to be able to take temporary steps to ensure bulk power system reliability until alternative permanent solutions can be developed and implemented. In some cases, it may be necessary and advisable to plan for the loss of non-consequential load rather than to risk more widespread systemic problems. The proposed standard requires that the planner must document the situation necessitating the use of Non-Consequential Load Loss including alternatives evaluated in the planning assessment to ensure transparency. This represents an improvement over the existing TPL standards which allow for planned load loss without documentation of the circumstances that necessitated dropping load.

- Requirements R3 and R4[21]

The proposed Requirement R3 describes the requirements for steady state studies and the proposed Requirement R4 elucidates the requirements for stability studies. This is an improvement from the existing standard in which the study requirements for stability and steady state analysis were combined creating confusion.

[21] TPL-001-2 Requirements R3 and R4 largely mirror each other. R3 addresses the steady state portion of the Planning Assessment while R4 addresses the stability portion.

- In addition, the proposed TPL-001-2, Requirement R3, Part 3.3.1 and Requirement R4, Part 4.3.1 require that simulations faithfully duplicate what will happen in an actual power system based on the expected performance of the Protection Systems. These requirements ensure that if a Protection System is designed to remove multiple Elements from service for an event that the simulation will be run with all of those Elements removed from service. This proposal instills event-based analysis over simple Element analysis which will provide for more accurate simulations.
- Proposed Requirement R3, Parts 3.3.1.1 and 3.3.1.2 are new requirements that ensure that steady state analyses include: (1) the impact of subsequent tripping of generators for voltage ride through or steady-state voltage limits, and (2) tripping of transmission elements where relay loadability limits are exceeded. This will provide consistent treatment of the event impacts and improve the accuracy of the simulation.
- Requirement R4, Parts 4.3.1.1, 4.3.1.2 and 4.3.1.3 are new requirements that ensure that the stability analyses include: (1) the impact of subsequent successful and unsuccessful high-speed re-closing of circuits, (2) tripping of generators for low-voltage ride through, and (3) tripping of transmission lines and transformers where transient swings cause Protection System operation. This will ensure consistent treatment of event impacts and improve the accuracy of the simulations.
- The proposed TPL-001-2, Requirement R3, Part 3.3.2 and Requirement R4, Part 4.3.2 each require simulation of expected automatic operations of existing

and planned control devices with more detail than the existing TPL standards. This will ensure consistent treatment of the event impacts and improve the accuracy of the simulation.

- The proposed TPL-001-2, Requirement R3, Part 3.4.1 and Requirement R4, Part 4.4.1 are new requirements that assure the planners coordinate with other Transmission Planners and Planning Coordinators to develop their Contingency list to ensure that contingencies on adjacent systems that may impact the planner's system are included in the Contingency list. This will ensure coordination between planners and improve the accuracy of the simulation.
- The proposed TPL-001-2, Requirement R3, Part 3.5 and Requirement R4, Part 4.5 are new requirements that require the planners to conduct an evaluation of possible actions designed to reduce the likelihood or the consequences of extreme events that cause cascading. Table 1 of the existing TPL-004-1 standard required planners to evaluate the risk and consequences of Category 'D' events but did not require the evaluation of possible actions. The evaluation of possible mitigating actions provides transparency of possible solutions to minimize the likelihood and impact of cascading caused by extreme events.

- Requirement R5

The proposed TPL-001-2 offers improvement over the existing TPL standards related to voltage criteria and voltage performance. In proposed Requirement R5, each Transmission Planner and Planning Coordinator must have criteria for acceptable

System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its system. For transient voltage response the criteria shall, at a minimum, specify a low-voltage level and a maximum length of time that transient voltages may remain below that level. This requirement will establish more robust transmission planning for organizations and greater consistency as these voltage criteria are shared.

- Requirement R6

  Proposed Requirement R6 specifies that an entity must define and document the criteria or methodology used to identify system instability for conditions such as cascading, voltage instability, or uncontrolled islanding within its Planning Assessment. This specificity in identifying what some including the Commission refer to as "proxies" is an important clarification in the proposed revised standard and will lead to greater transparency in the planner's evaluation techniques. This transparency should enable better understanding of what is required in the assessment and lead to the adoption of more consistent criteria and methodologies as information is shared.

- Requirement R7

  Proposed Requirement R7 mandates coordination of individual and joint responsibilities for the Planning Coordinator and the Transmission Planner. This eliminates confusion regarding the responsibilities of the applicable entities and assures that all Elements needed for regional and Wide Area studies are defined with a specific entity responsible for each Element and that no gaps will exist in planning for the BPS.

- Requirement R8

  Proposed Requirement R8 addresses the sharing of Planning Assessments with neighboring Systems. The requirement ensures that information is shared with and input received from adjacent entities and other entities with a reliability related need that may be affected an entity's System planning.

- Withdrawal of TPL-005-0 and TPL-006-0 Reliability Standards

  This project recommends the dismissal of pending Reliability Standards TPL-005-0 and TPL-006–0. These standards required the Regional Reliability Organizations to assume certain regional and interregional assessment responsibilities. These standards mandated the Regional Reliability Organizations conduct assessments and supply the resulting data and reports to the ERO. This type of standard is no longer needed because the issue has been addressed by amendments to the ERO Rules of Procedure ("ROP"). The ROP allows the ERO to request reliability-related data and reports at any time and mandate that the requested entities must supply that information.[22]

- Table 1Steady State & Performance Planning Events

  Similar to the existing TPL standards, the proposed TPL-001-2 includes a table, Table 1, that serves as an integral part of the transmission planning reliability requirements. Table 1 describes system performance requirements for a range of potential system contingencies required to be evaluated by the planner. Many of the contingencies are similar to the existing table; however, the table has been revised to categorize the events as either "planning events" or "extreme events" compared to the existing

[22] NERC Rules of Procedure Sections 803 and 804. Available at http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20110825.pdf.

Category A, B, C, and D structure. The proposed table lists seven Contingency planning events (P1 through P7) that require steady-state and stability analysis as well as five extreme event contingencies – three for steady-state and two for stability. Each planning event and extreme event contains multiple sub-parts. The proposed table also includes a no Contingency "event" labeled as P0 which requires steady-state analysis.

The proposed Table 1will help establish more robust transmission planning across the ERO footprint and offers a number of enhancements over the existing TPL standards including:

- The proposed standard reclassifies some existing multiple Contingency (Category C) events as single Contingency planning events. The proposed planning event P2 includes bus faults and internal breaker faults as a single Contingency due to the events initiated by a single common mode condition that typically removes multiple BES facilities due to automatic action by Protection Systems. The proposed standard also establishes a higher performance level for these reclassified single Contingency events. Non-Consequential Load Loss and interruption of firm transfer is no longer permitted for the proposed P2 event when evaluating the extra-high voltage (> 300kV) ("EHV") Transmission Systems, which are considered the backbone of many Systems.
- In addition to the proposed P2 event described above, other planning events also include bifurcated performance criteria expectations placing a higher level of reliability on the EHV systems. Proposed planning events P4 (stuck

breaker) and P5 (relay failure) are multiple Contingency events which must also meet a higher level of reliability for the EHV systems. These changes are viewed as significant improvements in establishing BES reliability.

- The proposed planning event P3 is another enhancement that provides another example of an event whose performance requirement is presently treated as a multiple Contingency (Category C) event. A P3 event considers the loss of a generator unit followed by the loss of another single element such as a transmission circuit, generator, or transformer. Based on the high probability of a generator unit outage in combination with another facility outage, the proposed TPL-001-2 no longer allows the loss of non-consequential load or interruption of firm transfers for this event.
- Table 1 has also been enhanced by explicitly including reactive power shunt devices as an element outage that must be evaluated in various Contingency events.
- The proposed planning event P5 and the accompanying footnote 13 add clarity and consistency in how delayed Fault clearing will be modeled in planning studies. The SDT recognizes that the BES Protection Systems are complex systems and can vary widely in their design. However, the basic elements of any BES Protection System design involve inputs (current, d.c. voltage, a.c. voltage, *etc.*) to protective relays and outputs (trip signals, close signals, alarms, *etc.*) from protective relays. The SDT determined that a more focused approach than that utilized in the existing TPL standards was

desirable, so it adopted an approach that addresses specific relay types to more effectively analyze the impact of delayed Fault clearing.

- BES reliability issues associated with improper clearing of a Fault on the BES can result from the failure of hundreds of individual Protection System components in a BES substation. However, while the population of components that could fail and result in improper clearing is quite large, that population can be reduced dramatically by eliminating those components which share failure modes with other components. The critical components in BES Protection Systems are the protective relays themselves and a failure of a non-redundant protective relay will often result in undesired consequences during a Fault. Other Protection System components related to the protective relay could fail and lead to a BES issue, but the event to be studied would be identical, from both transient and steady state perspectives, to the event resulting from a protective relay failure if the population of protective relays to be considered is adequate.
- For example, the failure of a current transformer applied in a typical stepped distance transmission line protection system would compromise the system and likely prevent the distance relay from detecting a fault within its protection zone. The failure of the distance relay to function, regardless of root cause, would require reliance on protection systems functioning in a backup role to the failed distance relay. Similarly, the loss of a non-redundant pilot (communications) channel such as a fiber optic cable or microwave radio channel between two BES substations would result in delayed clearing for

faults near either end of a transmission line. However, the failure of the pilot relay would result in the same failure mode and lead to the same event in terms of BES reliability. Focusing on these critical components (the protective relays) allows the planner to efficiently assess the BES performance during almost any conceivable protection system failure pertinent to BES reliability.

- Virtually all BES protection systems fall into a few general design types centered on a few critical protective relay types and typically includes one or more tripping relays . Transmission line Protection Systems fall into three general classes of Protection Systems: (1) a stepped distance, impedance measurement-based system with distance relays applied, (2) a pilot-based system where directional or distance relays communicate Fault direction from end to end via a communications medium (*e.g.* fiber, power line carrier, etc.) where pilot relays and either distance or directional relays are applied, or (3) a multi-location current differential system with differential relays applied.
- Protection Systems designed to protect virtually any BES Facility in one location such as transformers, capacitor banks, reactors, busses, etc., generally fall into two general classes of protection systems: (1) a differential-based system with differential relays applied or (2) an over/under voltage/current system with current relays or voltage relays applied.
- Selecting an adequate population of protective relays to consider and focusing only on those failures will allow the planner to efficiently assess the performance of the BES during virtually any Protection System failure.

- The proposed TPL-001-2, Table 1, P5 events are limited to the Single Line to Ground ("SLG") Fault type consistent with the comparable C6 – C9 events from Table 1 in the existing TPL standards. The proposed TPL-001-2 standard treats SLG and three phase Faults as different events even if an SLG event migrates into a three phase Fault. Three phase events in the existing TPL standards are shown in Table 1, D1 – D4 and are retained in TPL-001-2, Table 1, extreme events.
- In total, this is an equal and effective alternative approach to match the performance requirements in Table 1 of the existing TPL standards. The proposed extreme events have been improved to require evaluation of Wide Area events including those based on operating experience as well as those initiated by a cyber attack. Overall, the proposed Table 1 adds significant clarity and raises the bar on performance expectations in several areas.

VI. JUSTIFICATION OF PROPOSED RELIABILITY STANDARDS

This section summarizes the development of the proposed Reliability Standard, TPL-001-2 — Transmission System Planning Performance Requirements and demonstrates the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

Exhibit D identifies the comments received on the various postings of the proposed Reliability Standard and discusses how the SDT addressed those comments. The complete development record for the proposed Reliability Standard is available in **Exhibit F**. This record includes the Standard Authorization Request ("SAR"), the draft of the proposed Reliability Standard 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 proposed Reliability Standard, and consideration of those comments by the SDT in developing the proposed Reliability Standard.

The purpose of the proposed TPL-001-2 standard 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."[23] The proposed TPL-001-2 standard applies to Planning Coordinators and Transmission Planners and consists of eight requirements and associated parts, addressing the following topics:

- Maintaining System models with consistent data including items in the Corrective Action Plan and representing projected System conditions
- Preparation of an annual Planning Assessment with requisite documentation and covering the Near-Term and Long-Term Transmission Planning Horizons for steady state, short circuit, and stability analysis
- Inclusion of sensitivity studies varying one or more conditions not already included in the normal studies by a sufficient amount to stress the system
- The need for a spare equipment strategy
- Defining when past studies may be used in the Planning Assessment
- Creation of Corrective Action Plans when performance is not met
- For steady state and stability analyses, defining the events that must be studied to ensure performance is maintained
- Defining the extreme events that must be studied
- Establishing criteria for acceptable voltage limits
- Establishing criteria for identifying system instability
- Determining responsibilities for performing studies
- Distribution of Planning Assessments to adjacent and necessary entities

Currently-effective Reliability Standards TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1 are proposed to be retired in their entirety. All of the requirements from these standards are now included in the proposed TPL-001-2 standard, and the reliability objectives of

[23] TPL-001-2 — Transmission System Planning Performance Requirements, at A.3.

the earlier TPL standards are met by the proposed standard. Additionally, Reliability Standards TPL-005-0 and TPL-006.1 will be withdrawn.

The implementation plan (**Exhibit B**) for this proposed standard requires compliance consistent with the scheduled effective dates of twelve, twenty-four, or eighty-four 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 twelve, twenty-four, or eighty-four months after NERC Board of Trustees adoption depending on the requirement as detailed in the implementation plan.

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

1. Proposed Reliability Standard is designed to achieve a specified reliability goal

The proposed Reliability Standard, TPL-001-2 — Transmission System Planning Performance Requirements, establishes 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 Contingencies. This standard includes specific requirements for Planning Assessments in both the near-term and long-term time horizons as well as studies for steady state, short circuit, and stability analysis and describes the coordination and documentation required to properly prepare such assessments.

2. Proposed Reliability Standard contains a technically sound method to achieve the goal

The proposed Reliability Standard contains technically sound methods to achieve the goal of establishing acceptable Transmission system planning performance. This proposed standard describes:

- What must be in the models employed in the assessment (Requirement R1).

- What studies must be performed and for what years in the respective time horizons they must be done (Requirement R2).
- Steady state (Requirement R3) and stability performance requirements (Requirement R4).
- Establishing criteria for voltage limits and responses (Requirement R5).
- Establishing criteria for defining conditions for voltage instability, cascading, and uncontrolled islanding (Requirement R6).
- Identification of respective responsibilities (Requirement R7).
- Distribution of the Planning Assessment (Requirement R8).

The requirements in the proposed Reliability Standard define the various aspects of planning that need to be completed by the planner to ensure that the as-planned system meets acceptable performance levels throughout the planning horizon. The details within the requirements provide the necessary specifics starting from the maintenance of the System models, through the simulations and assessments that need to be completed, the documentation of criteria and corrective action plans, and conclude with the distribution of the results of the planning assessment. When combined with the table, which articulates performance requirements for the planning and extreme events, the requirements frame the elements necessary to ensure that the system is planned to provide BES reliability.

3. Proposed Reliability Standard is applicable to users, owners, and operators of the bulk power system, and not others

The proposed Reliability Standard is applicable to users, owners, and operators of the bulk power system, and not others. The proposed standard is specifically applicable to Planning Coordinators and Transmission Planners, both of which are users, owners, or operators of the bulk power system.

4. Proposed Reliability Standard is clear and unambiguous as to what is required and who is required to comply

The proposed Reliability Standard is clear and unambiguous as to what is required and who is required to comply. Each requirement clearly states the applicable entities must comply with the requirement and what those entities are required to do. For example, Requirement R1 of the proposed revised standard now clearly states that Transmission Planners and Planning Coordinators shall maintain System models for performing the studies needed to complete their Planning Assessments as well as what conditions must be included in those models. It also defines the division of effort and responsibilities between the Planning Coordinator and the Transmission Planner (Requirement R7).

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

The proposed Reliability Standard includes clear and understandable consequences. Each primary requirement is assigned a Violation Risk Factor ("VRF") and a Violation Severity Level ("VSL") which supports the determination of a base penalty amount for violations of the requirements as required by NERC Sanction Guidelines. NERC's review of the VSLs for this proposed standard for consistency with FERC's VRF and VSL guidelines is included in Section VII and **Exhibit C** of this document.

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

The proposed Reliability Standard identifies clear and objective criteria to support enforcement in a consistent and non-preferential manner. Each requirement has an associated measure, and each requirement clearly identifies the expected performance that will serve as the basis for development of compliance enforcement objectives. The language used in the requirements clearly identifies what is expected of the applicable entity.

7. Proposed Reliability Standard achieves a reliability goal effectively and efficiently

The proposed Reliability Standard achieves their reliability goal effectively and efficiently. Expanding the requirements to meet the reliability objectives of the standards was carefully considered in the Reliability Standards development process, and the proposed standard was structured to address the objective without unduly burdening the applicable entities. For example, the implementation plan for the proposed standard has been phased to allow entities that have previously planned and designed their systems on the basis of the existing approach to single Contingencies time to transition to the new, higher performance requirements.

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

The proposed Reliability Standard is more stringent than current set of TPL standards in several areas. As described above, details of what model data must be utilized, requiring simulations to model actual behavior, and including actions from the Corrective Action Plan in subsequent years' data (Requirement R1), mandating sensitivity studies (Requirement R2, Parts 2.1.4 and 2.4.3), detailing a requirement for Contingency analysis (Requirement R3, Part 3.3 and Requirement R4, Part 4.3), establishing criteria for voltage limits, deviations, and response (Requirement R5), establishing criteria for identifying system instability conditions (Requirement R6), requiring distribution of Planning Assessments (Requirement R8), and elevating performance for facilities greater than 300 kV and eliminating dropping firm load for single contingencies (Table 1 - P1-2, P1-3, P2-1, P2-2, and P2-3), all reflect significant increases in responsibilities and expectations for applicable entities and clearly do not represent a lowest common denominator.

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

The proposed Reliability Standard does not differentiate among entities based on size or cost. These requirements apply to all Planning Coordinator and Transmission Planner entities with responsibility for planning equally.

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

The proposed Reliability Standard is designed to apply continent-wide. The proposed standard proposes no regional differences or variances.

11. **Proposed Reliability Standard causes no undue negative effect on competition or restriction of the grid**

NERC does not anticipate that the proposed Reliability Standard will adversely affect competition or restrict available transmission capability.

12. **The implementation time for the proposed Reliability Standardis reasonable**

The proposed Reliability Standard includes a reasonable implementation schedule for this standard. As noted, the proposed Reliability Standard is more stringent in several areas: details of what model data must be utilized, requiring simulations to model actual behavior, and including actions from the Corrective Action Plan in subsequent years data (Requirement R1), mandating sensitivity studies (Requirement R2, Parts 2.1.4 and 2.4.3), detailing requirement for Contingency analysis (Requirement R3, Part 3.3 and Requirement R4, Part 4.3), establishing criteria for voltage limits, deviations, and response (Requirement R5), establishing criteria for identifying system instability conditions (Requirement R6), requiring distribution of Planning Assessments (Requirement R8), and elevating performance for facilities greater than 300 kV and eliminating dropping firm load for single contingencies (Table 1 - P1-2, P1-3, P2-1, P2-2, and P2-3).

Additionally, NERC believes the proposed effective dates represent a reasonable time frame to allow all entities to adequately prepare for compliance with the new requirements. Compliance is already required for Reliability Standards TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1.

13. The Reliability Standard development process was open and fair

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 included in the Rules of Procedure as Appendix 3A. NERC's rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards. 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 a vote of stakeholders and the NERC Board of Trustees is required to approve a proposed Reliability Standard for submission to the applicable governmental authorities.

The proposed Reliability Standard set out in **Exhibit A** has been developed and approved by industry stakeholders using the process found in NERC's *Standard Processes Manual*, and was approved by the NERC Board of Trustees on August 4, 2011. Therefore, NERC developed the proposed standard in a manner that is open and fair.

14. Proposed Reliability Standard balances with other vital public interests

This proposed standard focuses on ensuring that transmission system planning performance principles within the planning horizon are met in order to develop a BES 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 reflected or considered in this proposed standard. NERC does not, however, anticipate any conflicts with other vital public interests.

15. Proposed Reliability Standard considers any other relevant factors

Exhibit D presents an overview of the issues raised in consideration of the proposed standard that demonstrates how industry comments, as well as directives from Order No. 693, are addressed in this standard development project.

VII. Violation Risk Factors and Violation Severity Levels

The proposed Reliability Standard includes VRFs and VSLs that are specific to individual Requirements. The ranges of penalties for violations of standards are based on the applicable VRFs and VSLs and will be administered based on the Sanctions Table and supporting penalty determination process described in NERC Sanction Guidelines, which is Appendix 4B in NERC's Rules of Procedure. The assignment of VRFs and VSLs included consideration of the NERC guidelines. Consistent with NERC's August 10, 2009 informational filing,[24] assignments of VRFs and VSLs were made at the main requirement level of the proposed standard.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in Reliability Standards, as defined in the ERO Sanction Guidelines. **Exhibit C** demonstrates the analysis of the chosen VRFs and VSLs in accordance with the VRF and VSL guidelines.

[24] *Informational Filing of the North American Electric Reliability Corporation Regarding the Assignment of Violation Risk Factors and Violation Severity Levels*, Docket Nos. RM08-11-000, RR08-4-000, RR07-9-000, and RR07-10-000 (August, 10, 2009).

VIII. SUMMARY OF THE RELIABILITY STANDARD DEVELOPMENT PROCEEDINGS

a. 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. NERC's rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards .

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 a vote of stakeholders and the NERC Board of Trustees is required to approve a proposed Reliability Standard before its submission to the applicable governmental authorities.

The proposed Reliability Standard set out in **Exhibit A** was approved by the NERC Board of Trustees on August 4, 2011.

b. Progress in Improving Proposed Reliability Standards

NERC continues to develop new and revised Reliability Standards that address the issues NERC identified in its initial filing of proposed Reliability Standards on April 4, 2006, the concerns noted in the FERC Staff Report issued on May 11, 2006 and the directives FERC has included in multiple subsequent orders pertaining to NERC's Reliability Standards.[25] NERC has incorporated these activities into its *Reliability Standards Development Plan: 2011-2013*, submitted to FERC on April 13, 2011.

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[25] *Mandatory Reliability Standards for the Bulk-Power System*, 118 FERC ¶ 61,218, FERC Stats. & Regs. ¶ 31,242 (2007) ("Order No. 693"), *order on reh'g*, *Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 ("Order No. 693-A") (2007).

c. Development History

On April 2, 2002, NERC received, and the Standards Committee accepted, a standards authorization request ("SAR") proposing to establish a standard for assessing and planning the transmission systems in North America. The SAR was posted for two industry comment opportunities and then approved by the Standards Committee for standard development on November 18, 2005. The project was delayed in starting, but work resumed in late 2006. Due to the amount of time between the acceptance of the SAR and the start of work, a supplemental SAR was drafted to incorporate changes in thinking on planning needs during the delay. The supplemental SAR was posted once for industry comment and was accepted by the Standards Committee on April 10, 2007 as *Project 2006-02: Assess Transmission Future Needs and Develop Transmission Plans*.

The assigned SDT posted the draft standard for a 45-day industry comment period from September 12, 2007 to October 26, 2007. In response, 80 sets of comments were received from representatives of 80 organizations representing 233 individuals and 9 of the 10 industry segments. Comments primarily addressed the proposed definitions, sensitivity studies, Corrective Action Plans, modeling data, and performance issues.

The SDT revised the draft standard accordingly and re-posted for industry comment from August 14, 2008 to September 29, 2008. This time, 80 sets of comments were received from 100 organizations representing 150 individuals and 9 of the 10 industry segments. The comments received focused on the revised definitions, maintenance of system models; items to be included in Planning Assessments and studies; merger of the steady state and stability performance tables; measures; VRFs; VSLs; and the implementation plan.

The SDT again revised the draft standard to accommodate industry concerns and posted the revised draft standard for comments between May 26, 2009 and July 9, 2009. There were 85 sets of comments from 85 organizations representing 170 individuals and 9 of the 10 industry segments. Comments dealt with revised definitions, clarity of requirements text, criteria for formal documentation of criteria for acceptable system steady state voltage limits, post-Contingency voltage deviations, transient voltage response, and revisions to the implementation plan.

NERC posted the fourth draft of the standard from September 16, 2009 through October 16, 2009. There were 67 sets of comments from 85 companies representing 180 individuals and all of the ten Industry Segments. In response to these stakeholder comments, the SDT modified one definition, and made some small clarifying modifications to the requirements, measures, and compliance elements. The SDT did not believe that the changes were substantive and requested approval from the Standards Committee to move to the ballot process.

d. Issues Raised during the Development Process including Minority Issues

During the development process, the SDT considered the following comments, issues, and concerns. The minority issues are issues raised by commenters during the development process that the SDT chose not to address in the manner that a minority of commenters preferred.

- Some commenters wanted two separate performance tables – one for steady state and one for stability. This would have resulted in a great deal of repeated text and would have created confusion at times as to where to go for guidance. In addition, it may have created a maintenance problem. The SDT decided to incorporate all of the necessary requirements into one cohesive, comprehensive Reliability Standard with one encompassing performance table.

- The currently enforceable Reliability Standards are unclear as to what data the planner should utilize in their assessments and studies. The SDT addressed this problem by establishing a definitive starting point; requiring that simulations mirror actual conditions and mandating that data from the previous Corrective Action Plans be incorporated into subsequent year's studies.
- The SDT had to answer questions such as: "what year(s) needed to be studied?" and "do studies need to be run for every year in the planning horizon?" The SDT determined that assessments must be completed every year but only specific years in the Planning Horizon need to be studied. Due to the cyclical nature of the assessments, once this proposed Reliability Standard is approved and implemented it will result in a portfolio of studies covering the different years in the planning horizon. Additionally, the SDT defined the circumstances when an entity could utilize past studies in its assessment.
- The SDT believed that Systems needed to be stressed in the studies in order to ensure that proper planning takes place. This led to the inclusion of mandatory sensitivity studies as part of the planning process. This will force planners to stress their Systems beyond levels typically seen in existing studies and could point to potential problem areas that may have previously remained undetected.
- A need exists to ensure that Wide Area coordination is taking place in the assessments and studies. The SDT was concerned that planning may be

taking place in a vacuum without sufficient understanding of what takes place in neighbors Systems. To address this concern, the SDT crafted several requirements starting with studying contingencies in adjacent Systems and finishing by requiring the distribution of Planning Assessments to affected entities.

- The SDT needed to incorporate the Order No. 693 directive barring the loss of non-consequential load for single contingencies.[26] Through the various industry comment periods, the SDT created the new performance criteria and detailed the process in footnotes 9 and 12.
- The SDT wanted to heighten System performance by crafting more stringent performance criteria for certain parts of the System. The SDT accomplished this by creating a dividing line at the 300 kV level. Anything above 300 kV is considered to be the backbone of the interconnected transmission System and it was therefore determined by the SDT that more stringent criteria was warranted at that level.

<u>Minority Issues</u>

- Interchange should not be modeled because it is an economic issue and not involved in reliability.

  <u>Response:</u>

  The SDT countered that the proposed TPL-001-2 standard requires inclusion of known commitments for interchange and is not for economic purposes, but rather planning to meet obligations.

[26] Order No. 693 at P 1794.

- Dynamic behavior of Load should not be required in the model, claiming that software was not developed enough to be accurate.

  Response:

  The SDT believes that the correct modeling of the characteristics of Load is an important aspect of having an accurate model. The requirement to represent the dynamic behavior of the Load is necessary to ensure BES reliability.

- Distribution of Planning Assessments should not be required, as it creates a large workload for the entities involved.

  Response:

  The standard only requires distribution of the Planning Assessment, which should not require a large amount of work; posting the Planning Assessment could meet the requirement to distribute.

- TPL-001-2 should not move forward until footnote 'b' is resolved with FERC.

  Response:

  Any changes in response to FERC actions can easily be folded back into TPL-001-2. The improvements to System planning associated with approval of the new standard should not be delayed.

e. Initial Ballot

NERC conducted an initial ballot from February 19, 2010 through March 1, 2010. With a 91.38 percent quorum participating in the ballot, the proposed Reliability Standard achieved a weighted segment vote of 35.36 percent. There were 168 negative ballots submitted for the initial ballot, and 103 of those ballots included a comment, which created a need for a recirculation ballot. However, due to the massive number of negative votes and changes required to accommodate the voter's concerns, the SDT decided to re- post the standard in order to properly vet the changes made to the proposed standard.

There were five main themes to the comments supplied with the initial balloting:

1. Loss of Non-Consequential Load: A large number of commenters felt that the SDT was not allowing for Non-Consequential Load Loss in as many situations as the old standard.

2. Description of the Table 1 P5 event (Fault plus Protection System failure to operate): NERC received many comments regarding the use of the defined term, Protection System, in the event description. These commenters stated that fully redundant protection systems would be required on all BES equipment to meet the performance requirements for P5, which is not required by the existing standards. The SDT clarified that its intent was not to require fully redundant protection systems on all BES equipment in revised language for P5.

3. Relay and Load modeling: Comments expressed the opinion that the proposed Reliability Standard would require the addition of detailed relay models and detailed dynamic load models into the planning models. These commenters expressed the opinion that these additions would create large volumes of additional work and extend the computation time for very little reliability benefit. The commenters further stated that the dynamic load models are not developed enough to require their use in Reliability Standards. . (This is addressed in the Minority Issues section VIII.b above.)

4. Spare equipment strategy: Several commenters believed that a spare equipment strategy does not belong in the planning standard.
5. Implementation timeframe: Many requests were made to extend the implementation timeframe from 60 to 84 months.

f. Balloting and Approval

The SDT addressed all of the ballot comments[27] and made several changes to the proposed standard as a result. The SDT posted its Consideration of Comments reports to the initial ballot comments as part of a posting from August 3, 2010 through September 2, 2010. Comments were received from 77 different people from approximately 69 companies representing six of the ten Industry Segments. Based on stakeholder comments, the SDT modified one definition, and made clarifying changes to requirements, measures, and compliance elements. The SDT did not believe that the changes were substantive and requested approval from the Standards Committee to again move to the ballot process.

NERC posted the proposed standard as part of a concurrent posting/balloting period from April 18, 2011 through May 31, 2011. With a 92.07 percent quorum participating in the ballot, the proposed Reliability Standard achieved an affirmative weighted segment vote of 73.99 percent. There were 72 negative ballots with comments submitted for the initial ballot, which created the need for a recirculation ballot. NERC conducted the recirculation ballot from July 13, 2011 through July 24, 2011. With a 94.33 percent quorum participating in the ballot, the proposed Reliability Standard achieved a weighted segment approval vote of 75.37 percent. The proposed Reliability Standard achieved the required two-thirds weighted segment vote and at least a 75 percent quorum of the ballot pool.

[27] *See* Exhibit D for consideration of comments and Exhibit F for the complete development history.

The NERC Board of Trustees approved the proposed standard during its August 4, 2011 meeting.

IX. CONCLUSION

For the reasons stated above, NERC requests that the AESO take the steps necessary to adopt the proposed standard included in this filing.

Respectfully submitted,

/s/ Andrew M. Dressel

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Exhibits A - G

(Available on the NERC Website at
http://www.nerc.com/fileUploads/File/Filings/Attachments_TPL-001.pdf)