Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.

Proposed Action Plan and Description of Current Draft:

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

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

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

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

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

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

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

In summary, the SDT heard that:

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

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

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

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

- Interruptible Demand or Demand-Side Management

Future Development Plan:

Anticipated Actions	Anticipated Date
1. 30-day posting	September 2010
2. 30-day pre-ballot period	November 2010
3. Initial ballot	December 2010
4. Recirculation ballot	January 2011
5. Submit to BOT for approval	January 2011
6. File with FERC	February 2011

A. Introduction

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

2. Number: TPL-001-1

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

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

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

B. Requirements

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

R1.1. Be made annually.

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

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

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

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

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

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

R1.3.5. Have all projected firm transfers modeled.

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

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

R1.3.8. Include existing and planned facilities.

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

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

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

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

R2.1.1. Including a schedule for implementation.

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

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

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

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

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-1_R1 and TPL-001-1_ R2.

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

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
Compliance Monitor: Regional Reliability Organization.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame
Annually

1.3. Data Retention
None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

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

2.3. Level 3: Not applicable.

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

E. Regional Differences

1. None identified.

Version History

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

Table I. Transmission System Standards – Normal and Emergency Conditions

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

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

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

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

- Demand that is directly served by the elements that are removed from service as a result of the Contingency
- Interruptible Demand or Demand-Side Management
- Demand that does not adversely impact overall BES reliability where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

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

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

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

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

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