Exhibit K.T.2.3
for EB-2017-0364

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Regional Reliability Reference Directory # 1
Design and Operation of the Bulk Power System

Task Force on Coordination of Planning Revision Review Record:
December 01, 2009
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Adopted by the Members of the Northeast Power Coordinating Council, Inc., on December 01, 2009 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	12/1/2009		New
1	4/20/2012	Errata Changes in Appendices B and E.	Errata
2	9/30/2015	TFCP/TFCO Review	Revised

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1.0 Introduction

1.1 Title: Design and Operation of the Bulk Power System

1.2 Directory Number: 1

1.3 Objective:

The objective of this Directory is to provide a "design-based approach" to design and operate the **bulk power system** to a level of reliability that will not result in the loss or unintentional separation of a major portion of the system from any of the contingencies referenced in **Requirement R7** and **Requirement R13.** The intent of this approach is to avoid instability, voltage collapse and widespread cascading outages. Loss of small portions of a system (such as radial portions) may be tolerated provided these do not jeopardize the reliability of the remaining **bulk power system.**

In NPCC the technique for achieving this level of reliability is to require that the **bulk power system** be designed and operated to meet the performance requirements for the representative **contingencies** as specified in this Directory. Simulations shall be used to assess and analyze these **contingencies.** As a minimum**, contingency** events shall be applied on **bulk power system** elements and the resulting performance requirements shall be monitored on the **bulk power system.** If an entity becomes aware[1] of a **contingency** not on a **bulk power system** element that results in a **significant adverse impact** outside the **local area,** that entity must design and/or operate the system to respect that event.

The characteristics of a reliable **bulk power system** include adequate **resources** and transmission to reliably meet projected customer electricity **demand** and energy requirements as prescribed in this document.

1.4 Effective Date: December 1, 2009

1.5 Background

This Directory was developed from the NPCC A-2 criteria document - *Basic Criteria for the Design and Operation of Interconnected Power Systems* (May 6, 2004 version). Guidelines and Procedures for consideration in the implementation of this Directory are provided in the Appendices.

[1] NPCC Members shall strive to meet the reliability objectives in this document. However, there is no affirmative requirement for an NPCC Member to explicitly identify every potential non-BPS contingency that may impact the BPS.

1.6 Applicability

1.6.1 Functional Entities

Reliability Coordinators
Transmission Operators
Balancing Authorities
Planning Coordinators
Transmission Planners
Resource Planners
Generator Owners
Transmission Owners

1.6.2 Applicability of NPCC Criteria:

The requirements of an NPCC Directory apply only to those facilities defined as NPCC **bulk power system** elements as identified through the performance based methodology of NPCC Document A-10, *"Classification of Bulk Power System Elements*," the list of which is maintained by the NPCC Task Force on System Studies and approved by the NPCC Reliability Coordinating Committee.

Requirements to abide by an NPCC Directory may also reside in external tariff requirements, bilateral contracts and other agreements between facility owners and/or operators and their assigned Reliability Coordinator, Planning Coordinator, Transmission Operator, Balancing Authority and/or Transmission Owner as applicable and may be enforceable through those external tariff requirements, bilateral contracts and other agreements. NPCC will not enforce compliance to the NPCC Directory requirements in this document on any entity that is not an NPCC Full Member.

2.0 Defined Terms:

Unless specifically noted in this document terms in bold typeface are defined in the NPCC Glossary of Terms.

3.0 NPCC Full Member Criteria:

Information for Planning and Operational Assessments

R1 Each Functional Entity that owns equipment shall submit verified information representing the physical or control characteristics of its equipment for system modelling and reliability analysis of the **bulk power system** in accordance with **Requirement R2**.

R2 Each Planning Coordinator and Reliability Coordinator shall collect and maintain information needed for system modelling and reliability analysis of the **bulk power system.**

R2.1 System modelling information shall be submitted to an NPCC Task Force upon request.

R3 Each Reliability Coordinator shall share and coordinate forecast system information and real-time information to enable and enhance the analysis and modeling of the interconnected **bulk power system** by security application software on energy management systems.

Resource Adequacy

R4 Each Planning Coordinator or Resource Planner shall probabilistically evaluate **resource** adequacy of its Planning Coordinator **Area** portion of the **bulk power system** to demonstrate that the loss of **load** expectation (LOLE) of disconnecting **firm load** due to **resource** deficiencies is, on average, no more than 0.1 days per year.

R4.1 Make due allowances for **demand** uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator **Areas**, transmission transfer capabilities, and **capacity** and/or **load** relief from available operating procedures.

R5 Each Planning Coordinator shall report and obtain Reliability Coordinating Committee (RCC) approval for its Review of **Resource** Adequacy. Appendix D provides guidance for the Area Review of **Resource** Adequacy.

R5.1 The Review of **Resource** Adequacy will be presented to the NPCC Task Force on Coordination of Planning (TFCP). Comprehensive and Interim reviews shall be presented to the TFCP before the beginning of the first time period covered by the assessment.

R5.2 A Comprehensive Review of **Resource** Adequacy is required every three years and will cover a time period of five years. If changes in planned facilities or forecasted system conditions warrant, TFCP may require a Comprehensive Review of **Resource** Adequacy in less than 3 years.

R5.3 In subsequent years, each Planning Coordinator shall conduct an Annual Interim Review of **Resource** Adequacy that will cover, at a minimum, the remaining years studied in the Comprehensive Review of **Resource** Adequacy.

R6 Each Reliability Coordinator shall coordinate outages and deratings of **resources** to verify adequate **resources** will be available to meet the forecasted **demand** and **reserve** requirements. Appendix F provides guidance for Operational Planning Coordination.

R6.1 A Summer and Winter Reliability Assessment will be presented to the NPCC Task Force on Coordination of Operation (TFCO) every year.

Transmission Planning

R7 Each Transmission Planner and Planning Coordinator shall plan its **bulk power system** to have sufficient transmission capability to meet the respective requirements as specified in Table 1 while serving forecasted **demand**.

R7.1 Credible combinations of system conditions which stress the system shall be modelled including, **load** forecast, inter-**Area** and intra-**Area** transfers, transmission configuration, active and reactive **resources**, **generation** availability and other dispatch scenarios. All **reclosing** facilities shall be assumed in service unless it is known that such facilities will be rendered inoperative.

R8 Each Transmission Planner and Planning Coordinator shall assess the impact of the extreme **contingencies** listed in Table 2. Appendix C provides guidance for testing and analyzing extreme **contingencies**.

R9 Each Transmission Planner and Planning Coordinator shall assess the impact of extreme system conditions, one condition at a time, subject to **contingencies** as listed in the "Extreme System Conditions" category of Table 2.

R10 Each Transmission Planner and Planning Coordinator shall have procedures and implement a system design that ensures equipment capabilities are adequate for **fault** current levels with all transmission and **generation** facilities in service for all operating conditions which are not prohibited by a procedure and coordinate these procedures with materially affected Transmission Planner and Planning Coordinator Areas.

R11 Each Planning Coordinator shall conduct and obtain Reliability Coordinating Committee (RCC) approval for its Transmission Review. Appendix B provides guidance for Transmission Reviews.

R11.1 A Comprehensive Transmission Review is required at least once every five years or if major or pervasive system changes have occurred. If changes in the planned facilities or forecasted system conditions warrant, the Task Force on System Studies (TFSS) may require a Comprehensive Transmission Review in less than five years.

R11.2 The proposal for the type of annual Transmission Review shall be presented to TFSS by March of the year during which the review is conducted. Approval for the type of Transmission Review shall be obtained from the TFSS. The annual Transmission Review shall be presented to the TFSS by April of the following year.

R11.3 If the results of the Transmission Review indicate that the planned **bulk power system** will not be in conformance with NPCC Directory #1, the Transmission Review shall incorporate a corrective action plan to achieve conformance.

Special Protection Systems

R12 Each Functional Entity that proposes a new or modified **SPS** shall consider the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits.

R12.1 Provide a rationale and justification to the TFCP including factors such as project delays, temporary construction configurations, unusual combinations of system conditions, equipment outages and infrequent **contingencies**.

Transmission Operation

R13 Each Reliability Coordinator and Transmission Operator shall establish **normal transfer capabilities** and **emergency transfer capabilities, for** its portion of the **bulk power system** to meet the respective performance requirements for the **contingencies** as specified in Table 3.

R14 Each Reliability Coordinator and **Transmission** Operator shall operate to **normal transfer capabilities** unless an **emergency,** in accordance with NPCC Directory# 2, is identified.

R15 Each Reliability Coordinator and Transmission Operator shall make system adjustments once an **emergency** has been identified, including the pre-**contingency** disconnection of **firm load,** to avoid exceeding **emergency transfer capabilities.**

R16 Each Reliability Coordinator and Transmission Operator shall assess the status of the **bulk power system** immediately after the occurrence of any **contingency** and prepare for the next **contingency** as specified in Table 3.

R16.1 Voltage reduction and shedding of **firm load** shall be deployed to return the system to a secure state, if other system adjustments are not adequate. Voltage reduction need not be initiated and **firm load** need not be shed to observe a post contingency loading requirement until the **contingency** occurs, provided that adequate response time for this action is available.

R16.2 System adjustments shall be completed as quickly as possible following any **contingency,** but within 30 minutes after the occurrence of any **contingency** specified in Table 3.

R17 Each Reliability Coordinator shall notify the applicable Reliability Coordinators of forced outages of any facility as per the NPCC Transmission Facilities Notification List and of any other condition which may impact inter-**Area** reliability.

R18 Each Reliability Coordinator shall coordinate scheduled outages of facilities that are on the NPCC Transmission Facilities Notification List sufficiently in advance of the outage to permit the affected Reliability Coordinators to maintain reliability. Appendix F provides guidance for Operational Planning Coordination.

R18.1 Review and update its Facilities Notification List and submit the list to the NPCC Task Force on Coordination of Operation (TFCO) annually.

R19 Each Reliability Coordinator shall coordinate voltage control between Transmission Operator Areas. Appendix G provides guidance for Inter- Reliability Coordinator **Area** Voltage Control.

R19.1 Metering for **reactive power resources** and voltage controller status shall be consistent between adjacent Transmission Operators.

R19.2 Upon request from the TFCO, perform an Inter-**Area** Voltage Control Assessment.

4.0 Compliance:

Compliance with the requirements set forth in this Directory will be in accordance with the NPCC Criteria Compliance and Enforcement Program (CCEP).

NPCC will not enforce a duplicate sanction for the violation of any Directory#1 requirement that is also required for compliance with a NERC Reliability Standard.

Prepared by:	Task Force on Coordination of Planning
Review and Approval:	Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval. Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC Bylaws" in effect at the time the ballots are cast. Revisions pertaining to the Appendices or other portions of the document such as links, etc., only require RCC approval. Errata may be corrected by the Lead Task Force at any time. This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.
References:	*NPCC Glossary of Terms* *Emergency Operations* (NPCC Directory #2) *Bulk Power System Protection Criteria* (NPCC Directory #4) *Reserve* (NPCC Directory #5) *Special Protection Systems* (NPCC Directory #7)) *Classification of Bulk Power System Elements* (A-10)

Table 1

Planning Design Criteria: Contingency events, Fault type and Performance requirements to be applied to bulk power system elements

Category	**Contingency** events Simulate the removal of all **elements** that **protection systems**, including **Special Protection Systems**, are expected to automatically disconnect for each event that involves an AC **fault.**	**Fault** type (permanent) On the listed **elements** where applicable	Performance requirements
I **Single Event**	1. **Fault** on any of the following: a. transmission circuit b. transformer c. shunt device d. generator e. bus section	Three-phase **fault** with **normal fault clearing**	i. to viii
	2. Opening of any circuit breaker or the loss of any of the following: a. transmission circuit b. transformer c. shunt device d. generator e. bus section	No **fault**	
	3. Loss of single pole of a direct current facility	No **fault**	
	4. **Fault** on any of the following: a. transmission circuit b. transformer c. shunt device d. generator e. bus section	Phase to ground **fault** with failure of a circuit breaker to operate and correct operation of a breaker failure **protection system** and its associated breakers	
	5. **Fault** on a circuit breaker	Phase to ground **fault,** with **normal fault clearing**	
***	6. Simultaneous **fault** on two adjacent transmission circuits on a multiple circuit tower.	Phase to ground **faults** on different phases of each circuit, with **normal fault clearing**	Double Circuit Contingencies: A&B, A&C, B&D, C&D
	7. Simultaneous permanent loss of both poles of a direct current bipolar facility	Without an ac **fault**	

Category	**Contingency** events Simulate the removal of all **elements** that **protection systems**, including **Special Protection Systems**, are expected to automatically disconnect for each event that involves an AC **fault.**	**Fault** type (permanent) On the listed **elements** where applicable	Performance requirements
	8. The failure of a circuit breaker to operate when initiated by a **SPS** after a **fault** on the following: a. transmission circuit b. transformer c. shunt device d. generator e. bus section	Phase to ground **fault**, with **normal fault clearing**	i. to viii
	9. The failure of a circuit breaker to operate when initiated by a **SPS** after opening of any circuit breaker or the loss of any of the following: a. transmission circuit b. transformer c. shunt device d. generator e. bus section	No **fault**	

Category	**Contingency** events Simulate the removal of all **elements** that **protection systems**, including **Special Protection Systems**, are expected to automatically disconnect for each event that involves an AC **fault**.	**Fault** type (permanent) On the listed **elements** where applicable	Performance requirements
II Event(s) after a first loss and after System Adjustment	1. Following the loss of any critical: a. transmission circuit, b. transformer, c. series or shunt compensating device or d. generator e. Single pole of a direct current facility and after System Adjustment, Category I **Contingencies** shall also apply.	Any Category I event as described above.	Performance requirements i to viii apply **Area generation** and **power** flows are adjusted between outages by the use of **resources** available within ten minutes following notification and other system adjustments such as HVDC and phase angle regulator adjustments that can be made within 30 minutes.

Performance Requirements for the contingencies defined in Table 1:

i. Loss of a major portion of the system or unintentional separation of a major portion of the system shall not occur.

ii. Loss of small or radial portions of the system is acceptable provided the performance requirements are not violated for the remaining **bulk power system**.

iii. Voltages and loadings shall be within applicable limits for pre-**contingency** conditions.

iv. Voltages and loadings shall be within **applicable limits** for post-**contingency** conditions except for small or radial portions of the system as described in ii.

v. The **stability** of the **bulk power system** shall be maintained during and following the most severe **contingencies**, with due regard to successful and unsuccessful **reclosing** except for small or radial portions of the system as described in ii.

vi. For each of the **contingencies** that involve **fault** clearing, **stability** shall be maintained when the simulation is based on **fault** clearing initiated by the **"system A" protection group** and also shall be maintained when the simulation is based on **fault** clearing initiated by the **"system B" protection group**. When applying this requirement to **contingency** event *#6*, the failure of a **protection group** shall apply only to one circuit at a time. When evaluating **contingency** event#4 breaker failure protection is assumed to operate correctly even if only a single breaker failure **protection system** exists.

vii. Regarding **contingency** event*#6* if multiple circuit towers are used only for station entrance and exit purposes and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded. Other similar situations can be excluded on the basis of acceptable risk, provided that the Reliability Coordinating Committee specifically accepts each request for exclusion. (See Appendix E.)

viii. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner except for small or radial portions of the system as described in ii.

Table 2

Planning Criteria: Extreme Contingency and System Conditions, Fault type and Performance Assessments to be applied to bulk power system elements

Category	Contingency events Simulate the removal of all elements that **protection systems**, including **Special Protection Systems,** are expected to automatically disconnect for each event that involves an AC **fault.**	**Fault** type (permanent) and/or condition applied On the listed **elements** where applicable	Performance to be assessed
	1. Loss of the entire capability of a generating station.	No **Fault**	
Extreme Contingency*	2. Loss of all transmission circuits emanating from a generating station, switching station, substation or dc terminal.	No **Fault**	
	3. Loss of all transmission circuits on a common right-of-way.	No **Fault**	
	4. **Fault** on of any of the following: a. transmission circuit b. transformer c. shunt device d. generator e. bus section	Three- phase **fault** with failure of a circuit breaker to operate and correct operation of a breaker failure **protection system** and its associated breakers. (with due regard to successful and unsuccessful reclosing.)	
	5. **Fault** on a circuit breaker	Three-phase **fault**, with **normal fault clearing**	
	6. Sudden loss of a large **load** or major **load** center.	No **Fault**	i, ii, iii
	7. The effect of severe power swings arising from disturbances outside the NPCC's interconnected systems.	**Fault** applied as necessary.	
	8. Failure of a **Special Protection System**, to operate when required following the normal contingencies listed in Table 1, Category I, Single Event.	As listed in Table 1, Category I, Single Event.	
	9. The operation or partial operation of a **Special Protection System** for an event or condition for which it was not intended to operate.	No **Fault**	
	10. Sudden loss of fuel delivery system to multiple plants, (e.g. gas pipeline contingencies).	No **Fault.**	
	Any additional extreme **contingencies** identified by each Planning Coordinator Area.	**Fault** applied as necessary.	

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Category	Contingency events Simulate the removal of all elements that **protection systems**, including **Special Protection Systems,** are expected to automatically disconnect for each event that involves an AC **fault.**	**Fault** type (permanent) and/or condition applied On the listed **elements** where applicable	Performance to be assessed
Extreme System Conditions	Contingency events listed in Table 1, Category I, Single Event	Peak **load** conditions resulting from extreme weather.	i (b, c), ii, iii
		Generating unit(s) fuel shortage (e.g. gas supply adequacy or low hydro) under normal weather peak conditions	i (c), ii, iii

Performance Assessment

i. Model the following pre-**contingency** conditions:

   a. transfers within or between Transmission Planner and Planning Coordinator Areas should be studied at values not expected to be exceeded more than 25% of the time.

   b. highly probable dispatch patterns of **generation** for the transfers being studied

   c. appropriate **load** representation (e.g. active and reactive power as a function of voltage) for transient tests and post transient **load** flows.

ii. Examine post **contingency** steady state conditions, as well as stability, overload, cascading outages and voltage collapse to obtain an indication of system robustness and determine the extent of any widespread system disturbance

iii. Where assessment concludes there are serious consequences, an evaluation of implementing a change to design or operating practices to address such contingencies shall be conducted.

Table 3

Operating Criteria: Contingency events, Fault type and Performance requirements to be applied to bulk power system elements to establish transfer capabilities.

	Contingency events Simulate the removal of all **elements** that **protection systems**, including **Special Protection Systems**, are expected to automatically disconnect for each event that involves an AC fault.	**Fault** type (permanent) On the listed **elements** where applicable	Performance requirements **Normal Transfer Capability**	Performance requirements **Emergency Transfer Capability** (only after an **Emergency** is identified)
	1. **Fault** on any of the following: a. transmission circuit b. transformer c. shunt device d. generator e. bus section	Three-phase **fault**, with **normal fault clearing**	i, ii, iii, iv, v, vi, vii, ix, x	i, ii, iii, iv, v, vi, vii, ix, xi
	2. Opening of any circuit breaker or the loss of any of the following: a. transmission circuit b. transformer c. shunt device d. generator e. bus section	No **fault**		
	3. Loss of single pole of a direct current facility	No **fault**		
	4. **Fault** on any of the following: a. transmission circuit b. transformer c. shunt device d. generator e. bus section	Phase to ground **fault** with failure of a circuit breaker to operate and correct operation of a breaker failure **protection system** and its associated breakers.	i,ii,iii,iv,v,vi,vii, viii, ix,x	**Contingency** Events 4 through 8 do not apply after an emergency is identified.
	5. **Fault** on a circuit breaker	Phase to ground **fault,** with **normal fault clearing**		
	6. Simultaneous **fault** on two adjacent transmission circuits on a multiple circuit tower.	Phase to ground **faults** on different phases of each circuit with **normal fault clearing**		
	7. Simultaneous permanent loss of both poles of a direct current bipolar facility	Without an ac **fault**		

	8. The failure of a circuit breaker to operate when initiated by a **SPS** after a **fault** on the following: a. transmission circuit b. transformer c. shunt device d. generator e. bus section	Phase to ground **fault**, with **normal fault clearing**	i,ii,iii,iv,v,vi,vii, viii, ix,x	**Contingency** Events 4 through 8 do not apply after an emergency is identified.
	9. The failure of a circuit breaker to operate when initiated by a **SPS** after an opening of any circuit breaker or the loss of any of the following: a. transmission circuit b. transformer c. shunt device d. generator e. bus section	No **fault.**		

Performance Requirements for the contingencies defined in Table 3:

i. Loss of a major portion of the system or unintentional separation of a major portion of the system shall not occur.

ii. Loss of small or radial portions of the system is acceptable provided the performance requirements are not violated for the remaining **bulk power system.**

iii. Individual Reliability Coordinator Areas shall be operated in a manner such that **Contingencies** and conditions applied can be withstood without causing **significant adverse impact** on other Reliability Coordinator Areas.

iv. Voltages and loadings shall be within applicable limits for the pre-**contingency** conditions.

v. Voltages and loadings shall be within **applicable limits** for post-**contingency** conditions except for small or radial portions of the system as described in ii.

vi. The **stability** of the **bulk power system** shall be maintained, with due regard to successful and unsuccessful **reclosing** except for small or radial portions of the system as described in ii.

vii. For each of the **contingencies** that involve **fault** clearing, **stability** shall be maintained when the simulation is based on **fault** clearing initiated by the **"system A" protection group**, and also shall be maintained when the simulation is based on **fault** clearing initiated by the **"system B" protection group**. When applying this requirement to **contingency** event#*6* the failure of a **protection group** shall apply only to one circuit at a time. When evaluating **contingency** event#4 breaker failure protection is assumed to operate correctly even if only a single breaker failure **protection system** exists

viii. Regarding **contingency** event#6 if multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded. Other similar situations can be excluded on the basis of acceptable risk, provided that the Reliability Coordinating Committee specifically accepts each request for exclusion. (See Appendix E.)

ix. Appropriate adjustments shall be made to Reliability Coordinator Area operation to accommodate the impact of **protection group outages**, including the **outage** of a **protection group** which is a part of a Type I **special protection system**. For typical periods of forced outage or maintenance of a **protection group**, it can be assumed, unless there are indications to the contrary, that the remaining **protection** will function as designed. If the **protection group** will be out of service for an extended period of time, additional adjustments to operations may be appropriate considering other system conditions and the consequences of possible failure of the remaining **protection group.**

x. Normal transfer levels shall not require system adjustments before attempting manual reclosing of elements unless specific instructions describing alternate actions are in effect to maintain stability of the **bulk power system.**

xi. Emergency transfer levels may require system adjustments before attempting manual reclosing of elements to maintain stability of the **bulk power system**.

Operating to the **contingencies** listed above in Table 3 is considered to provide an acceptable level of **bulk power system** security. However, under high risk conditions, such as severe weather, the expectation of the occurrence of contingencies not listed in Table 3 and/or the associated consequences may be judged to be significantly greater. When these conditions exist, consideration should be given to operating in a more conservative manner.

Appendix A - NERC ERO Reliability Standard Requirements:

The NERC ERO Reliability Standards containing requirements associated with this Directory but not necessarily enforceable in all NPCC areas include but may not be limited to:

3.1 EOP-001-2.1b - Emergency Operations Planning

3.2 FAC-011-2 - System Operating Limits Methodology for the Operations Horizon

3.3 IRO-002-2 - Reliability Coordination - Facilities

3.4 IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators

3.5 MOD-010-0 - Steady-State Data for Modeling and Simulation of the Interconnected Transmission System

3.6 MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures
FERC approved the withdrawal of MOD-011-0 pursuant to a letter order issued May 1, 2014 in Docket No. RD14-5-000. MOD-011-0 was replaced by MOD-032-1--- Standard subject to future enforcement.

3.7 MOD-012-0 — Dynamics Data for Modeling and Simulation of the Interconnected Transmission System

3.8 MOD-013-1 — RRO Dynamics Data Requirements and Reporting Procedures
FERC approved the withdrawal of MOD-013-1 pursuant to a letter order issued May 1, 2014 in Docket No. RD14-5-000. MOD-013-1 was replaced by MOD-032-1--- Standard subject to future enforcement.

3.9 MOD-014-0 — Development of Interconnection-Specific Steady State System Models
FERC approved the withdrawal of MOD-014-0 pursuant to a letter order issued May 1, 2014 in Docket No. RD14-5-000. MOD-014-0 was replaced by MOD-032-1--- Standard subject to future enforcement.

3.10 MOD-016-1.1 — Actual and Forecast Demands , Net Energy for Load, Controllable DSM

3.11 TOP-001-1a — Reliability Responsibilities and Authorities

3.12 TOP-002-2.1b— Normal Operations Planning

3.13 TOP-003-1 — Planned Outage Coordination

3.14 TOP-004-2 — Transmission Operations

3.15 TPL-001-0.1 — System Performance Under Normal (No Contingency) Conditions (Category A) Will be replaced by TPL-001-4 (R2 through R6 and R8). The inactive date for TPL-001.01 is 12/31/2015. Please see the details link for TPL-001-4 for more information.

3.16 TPL-001-4 — Transmission System Planning Performance Requirements

3.17 TPL-002-0b — System Performance Following Loss of a Single Bulk Electric System Element (Category B)
Will be replaced by TPL-001-4 (R2 through R6 and R8). The inactive date for TPL-002.0b is 12/31/2015. Please see the details link for TPL-001-4 for more information.

3.18 TPL-003-0b — System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
Will be replaced by TPL-001-4 (R2 through R6 and R8). The inactive date for TPL-003.0b is 12/31/2015. Please see the details link for TPL-001-4 for more information.

3.19 TPL-004-0a — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)
Will be replaced by TPL-001-4 (R2 through R6 and R8). The inactive date for TPL-004.0a is 12/31/2015. Please see the details link for TPL-001-4 for more information.

3.20 VAR-001-4 — Voltage and Reactive Control

Appendix B - Guidelines and Procedures for NPCC Transmission Reviews

1.0 Introduction

NPCC has established a Reliability Assessment Program to bring together work done by NPCC, Transmission Planners and Planning Coordinators relevant to the assessment of **BPS reliability**. As part of the Reliability Assessment Program, the Task Force on System Studies (TFSS) is charged on an ongoing basis with conducting periodic reviews of the **reliability** of the planned **bulk power system** of each Planning Coordinator Area of NPCC. The purpose of these reviews is to determine whether each Planning Coordinator Area's planned bulk power transmission system is in conformance with the NPCC Directory #1 *Design and Operation of the Bulk Power System.* The annual Area Transmission Review required in **Requirement R11** is presented for this purpose. It is expected that this Review will cover Directory #1 requirements as they apply to the **bulk power system.**

2.0 Purpose of Review Presentation

The purpose of the presentation associated with an Area Transmission Review is to demonstrate that the Planning Coordinator's planned **bulk power system** based on its projection of available **demand**, transmission, and **resources**, is in conformance with the Directory #1 criteria. By such a presentation, the Task Force will satisfy itself that the criteria have been met and, in general, that the **reliability** of the NPCC Interconnected Systems will be maintained.

3.0 Study Year To Be Considered

It is suggested that a study year of 4 to 6 years from the reporting date is a realistic one, both from the viewpoint of minimum lead times required for construction, and the ability to alter plans or facilities. The reviews may be conducted for a longer term beyond 6 years to address identified marginal conditions that may have longer lead-time solutions.

4.0 Types and Frequency of Reviews

As described in **Requirement R11,** each Planning Coordinator is required to present an annual transmission review to TFSS. However, the review presented by the Planning Coordinator may be one of three types: a Comprehensive (or Full) Review, an Intermediate (or Partial) Review, or an Interim Review.

A Comprehensive Review is a thorough assessment of the Planning Coordinator's entire **bulk power system**, and includes sufficient analyses to fully address all aspects of an Area Transmission Review as described in **Requirement R11.**

In the years between Comprehensive Reviews, Planning Coordinators may conduct either an Interim Review, or an Intermediate Review, depending on the extent of the Planning Coordinator's system changes since its last Comprehensive Review. If the system changes are relatively minor, the Planning Coordinator may conduct an Interim Review. In an Interim Review, the Planning Coordinator provides a summary of the changes in planned facilities and forecasted system conditions since its last Comprehensive Review and a brief discussion and assessment of the impact of those changes on the bulk power transmission system. No new analyses are required for an Interim Review.

If the Planning Coordinator's system changes since its last Comprehensive Review are moderate or concentrated in a portion of the Planning Coordinator's system, the Planning Coordinator may conduct an Intermediate Review. An Intermediate Review covers all the elements of a Comprehensive Review, but the analyses may be limited to addressing only those issues considered to be of significance, considering the extent of the system changes.

In March of each year, after a Planning Coordinator presents a proposal for the type of review to be conducted during the current year, TFSS will consider each Planning Coordinator's proposal. TFSS will either indicate their concurrence, or require the Planning Coordinator to conduct a more extensive review if the Task Force feels that such is warranted based on the Planning Coordinator's system changes since its last Comprehensive Review.

5.0 Format of Presentation – Comprehensive and Intermediate Review

a) Introduction

- Reference the most recent Area Comprehensive Review and any subsequent Intermediate or Interim reviews as appropriate.
- Describe the type and scope of this review.
- For a Comprehensive Review, describe the existing and planned **bulk power system** facilities included in this review.
- Describe changes in system facilities, **bulk power system elements** and **loads** since the most recent Comprehensive Review.
- Include maps and one-line diagrams of the system showing proposed changes as necessary.
- Describe the **demand** levels to be studied, according to the range of forecast system **demands.**
- Identify projected firm transfers and interchange schedules.

b) Present the scope of the analyses. The analyses conducted for a Comprehensive Review should be thorough, but an Intermediate Review may focus on specific areas of the system, specific system conditions, or a more limited set of "critical" **contingencies**.

c) Steady State Assessment

- Present the **load** model, power factor, **demand** side management, and other modeling assumptions used in the analysis. Discuss the methodology used in voltage assessments. (An Intermediate Review may refer to the discussion from the last Comprehensive Review.)

- Provide supporting information on the **contingencies** selected for evaluation and an explanation of why **contingencies** not simulated would produce less severe results.

- Provide information on the **generation** dispatch conditions assumed in the analysis.

- Include plots of "base case" **load** flows with all lines in service for the various conditions studied, e.g., peak, off-peak, and heavy transfers.

- Present the effects of major planned changes on the system.

- Identify applicable transfer limits within and between Planning Coordinator Areas.

- Show the adequacy of voltage performance and voltage control capability for the planned bulk power transmission system.

d) Stability Assessment

Present and/or refer to significant studies showing the effect of **contingencies** on the system and report on the most severe **contingencies** in the following manner:

- Provide supporting information on the **contingencies** selected for evaluation and an explanation of why **contingencies** not simulated would produce less severe results.

- The nature of the **fault** applied, **elements** switched, and **fault clearing** times.

- Plots of angles versus time for significant machines, response of real and reactive power control devices, voltages at significant buses and significant interface flows.

For a Comprehensive or Intermediate Review, present the **load** model and other modeling assumptions used in the analysis. (An Intermediate Review may refer to the discussion from the last Comprehensive Review.)

e) **Fault** Current Assessment

- Present the methodology and assumptions used in the **fault** current assessment. (An Intermediate Review may refer to the discussion from the last Comprehensive Review.)
- Present instances where **fault** levels exceed equipment capabilities and measures to mitigate such occurrences.
- Present changes to **fault** levels at stations adjacent to other Planning Coordinator Areas.

f) Extreme **Contingency** Assessment

- Present the scope of the analyses including a description of the system conditions assessed. The analyses conducted for a Comprehensive Review should be thorough, but an Intermediate Review may focus on specific areas of the system, specific system conditions, or a more limited set of "critical" **contingencies**.
- Provide supporting information on the extreme **contingencies** selected for evaluation and an explanation of why the remaining **contingencies** not simulated would produce less severe results.
- Review the results for widespread cascading due to overloads, instability or voltage collapse caused by extreme **contingencies**
- In the case where **contingency** assessment reveals serious consequences, conduct an evaluation of implementing a change to address such **contingencies**.

g) Extreme System Condition Assessment

- Present the scope of the analyses including a description of the system conditions assessed. The analyses conducted for a Comprehensive Review should be thorough, but an Intermediate Review may focus on specific areas of the system, specific system conditions, or a more limited set of "critical" **contingencies**.

- Provide the rationale for the loss of fuel supply conditions selected for evaluation and an explanation of why other loss of fuel supply conditions not simulated would produce less severe results.

- Provide supporting information on the **contingencies** selected for evaluation and an explanation of why the remaining **contingencies** not simulated would produce less severe results.

- In the case where extreme condition assessment reveals serious consequences, conduct an evaluation of implementing measures to mitigate such consequences.

h) Review of **Special Protection Systems (SPSs)**

- Present the scope of review. A Comprehensive Review should review all the existing, new and modified **SPSs** included in its transmission plan. An Intermediate Review may focus on the new and modified **SPSs**, and just those existing **SPSs** that may have been impacted by system changes since they were last reviewed.

- Present the need and utilization for Type I and Type II **SPSs.** For instances where a **SPS** utilization is anticipated to increase, the TFSS should inform the Task Force on Coordination of Planning (TFCP) of this finding.

- Review the validity of the classification of Type III **SPSs**. For instances where a **SPS** which was formerly considered to have only local consequences is identified as having the potential for inter- Planning Coordinator Area effects, for the time period being reviewed, the TFSS should notify the Task Force on Coordination of Planning, System Protection and Coordination of Operation. In such instances a complete review of the **SPS** should be made, as per the *Procedure for NPCC Review of New or Modified Bulk Power System* ***Special Protection Systems*** *(SPS)* in Directory #7.

i) Review of Dynamic Control Systems (DCSs)

Review of potential consequences of failure or misoperation of Dynamic Control Systems (DCS), as defined in NPCC Document C-33 *Procedure for Analysis and Classification of Dynamic Control Systems*. For Type I and Type II DCSs, present and/or refer to appropriate **stability** studies analyzing the consequences of failure or misoperation in accordance with the Joint Working Group (JWG)-1 report, "Technical Considerations and Suggested Methodology for the Performance Evaluation of Dynamic Control Systems". A Comprehensive Review should address all potentially impactful existing and new DCSs, but an Intermediate Review may focus on new DCSs and only those existing DCSs that may have been impacted by system changes since they were last reviewed.

j) Review of Exclusions to the Directory#1 *Criteria*

Review any exclusions granted under NPCC *Guidelines for Requesting Exclusions to Simultaneous Loss of Two Adjacent Transmission Circuits on a Multiple Circuit Tower* (Appendix E). A Comprehensive Review should address all exclusions, but an Intermediate Review may focus on just those exclusions that may have been impacted by system changes since they were last reviewed.

k) Overview Summary of System Performance for Year Studied

6.0 Format of Presentation - Interim Review

a) Introduction of Interim Review

b) Reference the most recent Comprehensive Review and any subsequent Intermediate or Interim Reviews as appropriate.

c) Changes in Facilities (Existing and Planned) and Forecasted System Conditions Since the Last Comprehensive Review.

- **Load** Forecast
- **Generation Resources**
- **Bulk Power System elements**
- Transmission Facilities
- **Special Protection Systems**
- Dynamic Control Systems
- Exclusions

d) Brief Impact Assessment and Overview Summary

The Planning Coordinator will provide a brief assessment of the impact of these changes on the **reliability** of the interconnected **bulk power system**, based on engineering judgment and internal and joint system studies as appropriate.

7.0 Documentation

The documentation required for a Comprehensive or Intermediate Review should be in the form of a report addressing each of the items of the above presentation format. The report should be accompanied by the Planning Coordinator's **bulk power system** map and one-line diagram, summary tables, figures, and appendices, as appropriate. The report may include references to other studies performed by the Planning Coordinator or by utilities within the Planning Coordinator Area that are relevant to the Area Transmission Review, with appropriate excerpts from those studies.

The documentation required for an Interim Review should be in the form of a short summary report (normally not exceeding 5 pages), containing a description of system changes and a brief assessment on their impact on the **reliability** of the interconnected **bulk power system**

8.0 Task Force Follow-Up Procedures

8.1 Once a Planning Coordinator has presented its Transmission Review report to the TFSS, TFSS will review the Planning Coordinator's report and any supporting documentation and consider whether to accept the report as complete and in full conformance with these Guidelines :

a. If the report is found to be unacceptable, TFSS will indicate to the Planning Coordinator the specific areas of deficiency, and request the Planning Coordinator to address those deficiencies.

b. If there is no concurrence about the results and conclusion(s) of the Planning Coordinator's Review, TFSS will indicate to the Planning Coordinator the specific areas of disagreement, and work with the Planning Coordinator to try to achieve concurrence. If agreement has not been reached within a reasonable period of time, TFSS will prepare a summary of the results of its review, and present the summary to the TFCP.

c. If the report is considered as complete and in full conformance with these Guidelines, TFSS will accept the report.

8.2 If the Area Transmission Review indicates an overall **bulk power system** reliability concern (not specific to the Planning Coordinator's planned bulk power transmission system), TFSS will consider what additional studies may be necessary to address the concern, and prepare a summary discussion and recommendation to the Task Force on Coordination of Planning

8.3 Upon completion of an Area Review, TFSS will report the results of the review to the Task Force on Coordination of Planning. The TFCP will then review and vote on the completeness and acceptability of the Area Transmission Review and report its finding to the Reliability Coordinating Committee for a final review and approval.

Appendix C - Procedure for Testing and Analysis of Extreme Contingencies

1.0 Introduction

Extreme **Contingencies** (ECs) are tested "as a measure of system strength" in order to identify potential patterns of weakness in the bulk power transmission system. This procedure for the testing and analysis of ECs should be used when testing ECs for NPCC studies or studies submitted for NPCC review.

This procedure applies to transmission planning studies that consider the overall performance of the interconnected systems of the NPCC Planning Coordinator Areas. It principally applies to NPCC - wide studies of the **bulk power system** and generally does not apply to studies normally conducted by NPCC Transmission Planner and Planning Coordinators that concentrate on individual or a limited number of facilities. This procedure also applies to Area Transmission Reviews, and may be applicable to other studies conducted by the Transmission Planner and Planning Coordinators, and even to individual facility investigations, where such studies and investigations consider the overall performance of the interconnected systems of the NPCC Planning Coordinator Areas. Certain Transmission Planners or Planning Coordinators may elect to completely mitigate the effects of specific ECs.

Finally, this procedure should be followed in multi-regional studies in which NPCC is an active participant, to the extent that this is within the scope of such multi-regional efforts.

2.0 Choosing Contingencies for Testing

The ECs are defined as per **Requirement R8.** Testing should focus on those ECs expected to have the greatest potential effect on the interconnected system. Particular attention should be paid to **contingencies** which would result in major angular power shifts, e.g., interruption of shorter transmission paths carrying heavy power flows, leaving longer transmission paths as the only remaining paths. Additionally, **contingencies** which would result in reversal of major power transfers, e.g. loss of major ties in a neighboring region or Area when said region or Area was transferring power away from the area of interest, should be considered for their impact in subjecting the system to severe power swings. In considering specific **contingencies** to be investigated in an NPCC study, all relevant testing done at the Transmission Planner and Planning Coordinator level should first be reviewed.

In general, a **contingency** in a particular Planning Coordinator Area should be studied, if requested by any other Transmission Planner or Planning Coordinator, based on a reasonable surmise that the requesting Entity may be adversely affected.

3.0 Modeling Assumptions

As referenced in Table 2, performance assessment "i" for **Requirement R8**, the assumed **generation** dispatch, transfers levels, **load** levels and **load** representation are major considerations in EC tests. It is not the intent to test the worst imaginable extreme, but EC tests should be severe.

The specification of appropriate **load** representation applies to long term stability tests or post-transient power flows as well as **transient stability** tests.

4.0 Evaluating Individual Test Results

A question in evaluating the results of a particular test run is - "Does the system "pass" or "fail" for this **contingency**?" While in the final analysis this is a matter of informed engineering judgment, factors which should be considered include:

1. Lines or transformers loaded above **short time emergency ratings**,
2. Buses with voltage levels in violation of **applicable emergency limits**, (which vary depending on the location within the system),
3. Magnitude and geographic distribution of such overloads and voltage violations across the system,
4. Transient generator angles, frequencies, voltages and power,
5. Operation of Dynamic Control Systems and **Special Protection Systems** (**SPS**),
6. Oscillations that could cause generators to lose synchronism or lead to dynamic instability,
7. Net loss of source resulting from any combination of loss of synchronism of one or more units, **generation** rejection or runback initiated by SPS, or any other defined system separation,
8. Identification of the extent of the Planning Coordinator Area (s) involved for any indicated instability or islanding (the involvement of more than one Planning Coordinator Area, should be a major consideration),
9. **Relay** operations or the proximity of apparent impedance trajectories to **relay** trip characteristics,
10. The angle across opened breakers,

11. Adequacy of computer simulation models and data.

Finally, a judgment should be attempted as to whether a "failure" is symptomatic of a basic system weakness, or just sensitivity to a particular EC. For example, should failures turn up for several EC tests in a particular part of the system, it is likely that a basic system weakness has been identified.

The loss of portions of the system should not necessarily be considered a failed result, provided that these losses do not jeopardize the integrity of the overall **bulk power system.**

NPCC study groups should avoid characterizations like "successful" and "unsuccessful" when commenting on individual runs. Rather, the specific initial conditions directly causing or related to the failure, the complete description of the nature of the failure (e.g., voltage collapse, instability, system separation, as well as the facilities involved), and the extent of potential impact on other Planning Coordinator Areas should be reported.

5.0 Evaluating the Results of EC Tests

EC test reports should focus on those portions of the system in which basic system weaknesses may be developing, rather than on the results of one specific **contingency.**

Any patterns of weaknesses should be identified, which may include reference to earlier NPCC studies and/or Transmission Planner, Planning Coordinator or member system investigations. There is also a need to distinguish between a "failed" test which indicates sensitivity only to a particular **contingency** run and a "failed" test which indicates a more general system weakness (always keeping in mind the severity of possible consequences of the **contingency**). Actions taken by member systems, Transmission Planners or Planning Coordinators to reduce the probability of occurrence or mitigate the consequences of the **contingency** should also be cited.

NPCC follow-up, after publication of a final report, is appropriate only for instances of possible general system weakness. In these instances, the results should be specifically referred to the affected Transmission Planner(s) or Planning Coordinator(s) for further and more detailed investigation with subsequent reporting to NPCC.

Appendix D - Guidelines for Area Review of Resource Adequacy

1.0 Introduction

NPCC has established a Reliability Assessment Program to bring together work done by the NPCC and Planning Coordinators relevant to the assessment of **bulk power system reliability**. As part of the Reliability Assessment Program, each Planning Coordinator submits to the Task Force on Coordination of Planning its Area Review of **Resource** Adequacy, which is an annual assessment to demonstrate that the proposed **resources** of each NPCC Planning Coordinator will meet NPCC **resource** adequacy planning requirements, consistent with these guidelines. The Task Force is charged, on an ongoing basis, with reviewing and recommending NPCC Reliability Coordinating Committee approval of these reviews of **resource** adequacy of each Planning Coordinator Area of NPCC.

The NPCC role in monitoring conformance with the NPCC Directory #1 - *Design and Operation of Bulk Power System* is essential because under this criterion, each Planning Coordinator determines its **resource** requirements by considering interconnection assistance from other Planning Coordinators, on the basis that adequate **resources** will be available in those Planning Coordinator Areas. Because of this reliance on interconnection assistance, inadequate **resources** in one Planning Coordinator Area could result in adverse consequences in another Planning Coordinator Area.

It is recognized that all Planning Coordinators may not necessarily express their own **resource** adequacy criterion as stated in **Requirements R4**, **Requirement R5** and **Requirement R6** of the Directory #1 criteria. However, the Directory #1 criteria provide a reference point against which a Planning Coordinator's **resource** adequacy criterion can be compared.

2.0 Purpose of Presentation

The purpose of the presentation associated with a **resource** adequacy review is to show that each Planning Coordinator's proposed **resources** are in accordance with the NPCC Directory #1 - Design and Operation of the **Bulk Power System**. By such a presentation, the Task Force will satisfy itself that the proposed **resources** of each NPCC Planning Coordinator will meet the NPCC **Resource** Adequacy Requirements, as defined NPCC Directory #1, over the time period under consideration.

3.0 Format of Presentation and Report – Comprehensive Review

Each Planning Coordinator should include in its presentations and in the accompanying report documentation, as a minimum, the information listed below. At its own discretion, the Planning Coordinator may discuss other related issues not covered specifically by these guidelines.

3.1 Executive Summary

3.1.1 Briefly illustrate the major findings of the review.

3.1.2 Provide a table format summary of major assumptions and results.

3.2 Table of Contents

3.2.1 Include listing of all tables and figures.

3.3 Introduction

3.3.1 Reference the previous NPCC Area Review.

3.3.2 Compare the proposed **resources** and **load** forecast covered in this NPCC review with that covered in the previous review

3.4 **Resource** Adequacy Criterion

3.4.1 State the Planning Coordinator's resource adequacy criterion.

3.4.2 State how the Planning Coordinator criterion is applied; e.g., **load** relief steps.

3.4.3 Summarize **resource** requirements to meet the criteria for the time period under consideration. If interconnections to other Planning Coordinators and regions are considered in determining this requirement, indicate the value of the interconnections in terms of megawatts. In the calculation of available **resources**, supply-side **resources** from neighboring systems are limited to firm **capacity** backed purchases.

3.4.4 Provide either an estimate of the **resources** required to meet the NPCC criteria or a statement as to the comparison of the two criteria, if the Planning Coordinator criterion is different from the NPCC criterion

3.5 Resource Adequacy Assessment

3.5.1 Evaluate proposed **resources** versus the requirement to reliably meet projected electricity **demand** assuming the Planning Coordinator's most likely **load** forecast.

3.5.2 Evaluate proposed **resources** versus the requirement to reliably meet projected electricity **demand** assuming the Planning Coordinator's high **load** growth scenario.

3.5.3 Describe **load** and **resource** uncertainties on projected Planning Coordinator Area reliability and describe mechanisms to mitigate anticipated material adverse effects on reliability.

3.5.4 Describe anticipated effects from proposed major changes to market rules on Planning Coordinator Area reliability.

3.5.5 Summarize **resource** adequacy studies conducted since the previous Area Review, as appropriate

3.6 Reliability Impacts Due to Environmental Regulations and Fuel Supply Issues.

3.6.1 Discuss anticipated material adverse effects on reliability resulting from the proposed **resources** fuel supply and transportation.

3.6.2 Discuss anticipated reliability impacts related to an Area's compliance with State, Federal or Provincial requirements (such as environmental, renewable energy, or greenhouse gas reductions).

3.7 Mitigation Measures for Environmental Regulations and Fuel Supply Issues

3.7.1 Describe available mechanisms to mitigate anticipated reliability impacts of **resource** fuel supply, **demand resource** response, fuel transportation issues and/or environmental considerations.

4.0 Format of Presentation and Report – Annual Interim Review

The Annual Interim Review should include a reference to the most recent Comprehensive Review; a listing of major changes in: facilities and system conditions, **load** forecast, **generation resources** availability; related fuel supply and transportation information, environmental considerations, **demand** response programs, transfer capability and emergency operating procedures. In addition, the assessment should also include a comparison of major changes in market rules, implementation of new rules, locational requirements, and installed **capacity** requirements. Finally, the report should include a brief impact assessment and an overall summary.

The Planning Coordinator will provide a brief assessment of the impact of these changes on the reliability of the interconnected **bulk power system**. This assessment should be based on engineering judgment, internal system studies and appropriate joint interconnected studies. To the extent that engineering judgment or existing studies can be used to clearly demonstrate that a Planning Coordinator Area is expected to meet the NPCC **resource** adequacy criterion, detailed system LOLE studies are not required.

The documentation for the Annual Interim Review should be in the form of a summary report (normally not exceeding three to five pages.)

Sections A and B should describe the reliability model and program used for the **resource** adequacy studies discussed in Section 3.5. Section C should describe the Task Force follow-up procedures.

A. Description of Resource Reliability Model

1.1 **Load** Model

1.1.1 Description of the **load** model and basis of period **load** shapes.

1.1.2 How **load** forecast uncertainty is handled in model.

1.1.3 How the electricity **demand** and energy projections of interconnected entities within the Planning Coordinator Area that are not members of the Planning Coordinator Area are addressed.

1.1.4 How the effects (**demand** and energy) of **demand**-side management programs (e.g., conversion, interruptible **demand**, direct control **load** management, **demand** (**load**) response programs) are addressed.

1.2 Supply Side **Resource** Representation

1.2.1 **Resource** Ratings

1.2.1.1 Definitions.

1.2.1.2 Criteria for verifying **ratings**. Reference NPCC Directory#9 Verification of Gross and Net Real Power Capability and Directory#10 Verification of Gross and Net Reactive Power Capability.

1.2.2 Unavailability Factors Represented

1.2.2.1 Type of unavailability factors represented; e.g., forced outages, planned outages, partial derating, etc.

1.2.2.2 Source of each type of factor represented and whether generic or individual unit history provides basis for existing and new units

1.2.2.3 Maturity considerations, including any possible allowance for in-service date uncertainty.

1.2.2.4 Tabulation of typical unavailability factors.

1.2.3 Purchase and Sale Representation

1.2.3.1 Describe characteristics and level of dependability of transactions.

1.2.4 Retirements.

1.2.4.1 Summarize proposed retirements.

1.3 Representation of Interconnected System in Multi-Area Reliability Analysis, including which Planning Coordinator Areas and regions are considered, interconnection capacities assumed, and how expansion plans of other Planning Coordinators and regions are considered.

1.4 Modeling of Variable and Limited Energy Sources.

1.5 Modeling of **Demand** Side **Resources** and **Demand (Load)** Response Programs.

1.5.1 Description should include how such factors as in-service date uncertainty, **rating**, availability, performance and duration are addressed.

1.6 Modeling of all **Resources.**

1.6.1 Description should include how such factors as in-service date uncertainty; **capacity** value, availability, **emergency** assistance, scheduling and deliverability are addressed.

1.7 Other assumptions i.e., internal transmission limitations, maintenance over-runs, fuel supply and transportation and environmental constraints.

1.8 Incorporate the reliability impacts of market rules.

B. Other Factors, If Any, Considered in Establishing Reserve Requirement Documentation

The documentation required to meet the requirements of the above format should be in the form of summaries of studies performed within a Planning Coordinator Area, including references to applicable reports, summaries of reports or submissions made to regulatory agencies.

C. Task Force Follow-Up Procedures

Once a specific Planning Coordinator has made a presentation or a series of presentations to the Task Force on Coordination of Planning, the latter shall:

1.1 Prepare a brief summary of key issues discussed during the presentation.

1.2 Note where further information was requested and the results of such further interrogations.

1.3 Note the specific items that require additional study and indicate the responsibilities for undertaking these studies.

1.4 Recommend to the Reliability Coordinating Committee whether the **Resource** Adequacy Review is suitable for approval.

Appendix E - Guidelines for Requesting Exclusions to Simultaneous Loss of Two Adjacent Transmission Circuits on a Multiple Circuit Tower.

1.0 Introduction

Directory #1 allows for requests for exclusion from the simultaneous loss of two adjacent transmission circuits on multiple circuit towers on the basis of acceptable risk. All exclusions must be reviewed by the applicable Task Forces and approved by the Reliability Coordinating Committee (RCC). An acceptance of a request for exclusion is dependent on the successful demonstration that such exclusion is an acceptable risk. These guidelines describe the procedure to be followed and the supporting documentation required when requesting exclusion, and establishes a procedure for periodic review of exclusions of record.

2.0 Documentation

The documentation supporting a request for exclusion to the Criteria includes the following:

2.1 A description of the facilities involved, including geographic location, length and type of construction, and electrical connections to the rest of the interconnected power system;

2.2 Relevant design information pertinent to the assessment of acceptable risk, which might include: details of the construction of the facilities, geographic or atmospheric conditions, or any other factors that influence the risk of sustaining the loss of adjacent transmission circuits on a multiple circuit tower;

2.3 An assessment of the consequences of the loss of adjacent transmission circuits on a multiple circuit tower, including, but not limited to, a discussion of levels of exposure and probability of occurrence of **significant adverse impact** on the **bulk power system** ;

2.4 For existing facilities, the historical outage performance, including cause, for such **contingencies** on the specific facility (facilities) involved as compared to that of other multiple circuit tower facilities;

2.5 For planned facilities, the estimated frequency of adjacent transmission circuit multiple circuit tower **contingencies** based on the historical performance of facilities of similar construction located in an area with similar geographic climate and topography.

3.0 Procedure for obtaining an Exclusion

The following procedure is used to obtain an exclusion:

3.1 The entity requesting the exclusion (the Requestor) submits the request and supporting documentation to the Task Force on System Studies (TFSS) after acceptance has been granted by the Requestor's own Planning Coordinator, if such process is applicable.

3.2 TFSS reviews the request, verifies that the documentation requirements have been met, and determines the acceptability of the request.

3.3 If TFSS deems the request acceptable, TFSS requests the Task Force on Coordination of Planning (TFCP), the Task Force on Coordination of Operation (TFCO), and the Task Force on System Protection (TFSP) to review the request. The Requestor provides copies of the request and supporting documentation to the other Task Forces as directed by TFSS. If additional information is requested by the other Task Forces as part of their assessment, the Requestor provides this information directly to the interested Task Force, with a copy to the TFSS. The other Task Forces review the request and indicate their acceptance or non-acceptance to TFSS.

3.4 If all Task Forces deem the request for exclusion acceptable, the TFSS will forward a recommendation for approval to the RCC.

3.5 Exclusion requests will be effective upon approval by the RCC.

Appendix F – Procedure for Operational Planning Coordination

1.0 Introduction

The Reliability Coordinators (RC) of the Northeast Power Coordinating Council, Inc. (NPCC) require access to the security data specified in this procedure in order to adequately assess the reliability of the NPCC **bulk power system**. All users of the electric systems, including market participants, should supply such data to the NPCC Reliability Coordinators. Coordination among and within the Reliability Coordinator Areas (RC Area) of NPCC is essential to the reliability of interconnected operations. Timely information concerning system conditions should be transmitted by the NPCC RC Areas to other RC Areas as needed to assure reliable operation of the **bulk power system**. One aspect of this coordination is to ensure that adjacent RC Areas and neighboring systems are advised on a regular basis of expected operating conditions, including generator, transmission and system **protection**, including Type I **special protection system,** outages that may materially reduce the ability of an RC Area to contribute to the reliable operation of the interconnected system, or to receive and/or render assistance to another RC Area. To the extent practical, the coordination of outage schedules is desirable in order to limit the severity of such impacts.

To ensure that there is effective coordination for system **reliability** concerns, this document establishes procedures for the exchange of information regarding **load/capacity** forecasts, including firm sales and firm purchases, generator outage schedules, and transmission outage schedules for those **elements** that may have an adverse impact on other RC **Area(s)**. It also details general action that may be taken to improve the communication of problems as well as specific topics that may be discussed in regularly scheduled conference calls or ad -hoc conference calls arranged in anticipation of problems such as **capacity** deficiency or inadequate light **load** margin in one or more RC Areas.

NPCC participants and other recipients of the information provided by processes in this guideline should adhere to the NPCC Critical Energy Infrastructure Information Non – Disclosure agreement.

2.0 Load/Capacity Forecasts

2.1 Twice yearly by May 15th and November 15th respectively, the Operations Planning Working Group (CO 12) will perform a summer and winter assessment for the next season.

The results will be reviewed by the NPCC TFCO and the NPCC Reliability Coordinating Committee (RCC) during the spring and autumn meetings of both groups and documented in the summer and winter NPCC Reliability Assessment reports.

2.2 Each week, each RC Area will review its weekly net **resource capacity** margin, as defined in Attachment A, for the twelve weeks to follow and forward the information to the NPCC Staff for distribution to all NPCC RC **Areas**. If an NPCC RC Area identifies a deficiency or light **load** condition, the RC **Area** should identify the cause(s) and mitigation measures that have been implemented, or will be implemented, to manage the issue.

3.0 Generator Outage Coordination

3.1 Each RC **Area** should exchange current and expected generator outages that may have a significant impact on an adjacent RC **Area** or neighboring systems or a significant impact on the transfer capability between RC **Areas.**

4.0 Transmission Outage Coordination

4.1 <u>Advance Planning of Transmission Facility Outages</u>

Each RC should exchange critical transmission **element** outages as identified in the coordination agreements with their interconnected neighbors, **elements** identified on the Facilities Notification List and multiple transmission **element** outages that may have an adverse impact on external energy transfers. Each Reliability Coordinator shall minimize the duration of outages to facilities that impact inter-Reliability Coordinator Areas.

4.2 <u>Facilities Notification List</u>

The NPCC Facilities Notification List, Attachment D, has two components:

1) the NPCC Transmission Facilities Notification List; and
2) the list of NPCC Type I **special protection systems**.

The Facilities Notification List is developed by each RC Area and specifies all facilities that, if removed from service, may have a significant, direct or indirect impact on another RC Area's transfer capability. The cause of such impact might include stability, voltage, and/or thermal considerations.

Prior to October 1st of each year, each RC Area will review and update its Facilities Notification List and coordinate necessary changes with other appropriate NPCC RC Areas. Prior to January 1st, and after review by the TFCO, the jointly developed, updated and approved Facilities Notification List will be posted on the NPCC secure website.

It should be noted that revisions to the Facilities Notification List will not follow the NPCC Process for Open Review due to the secure nature of the information contained, and Attachment D is not openly published with this Procedure.

A temporary reconfiguration of the network may result in an outage to one or more facilities not listed in Attachment D having an impact on other NPCC RC Areas. It is the responsibility of the RC experiencing the condition to notify impacted RCs in a timely manner and provide updated status reports during the condition.

4.3 Notifications of Transmission **Element** Outages:

4.3.1 Notification requirements for Transmission **Element** Outages should be defined in interconnection coordination agreements. The time frames identified below are the minimum notification requirements.

4.3.2 Reliability Coordinators will advise affected RCs of all planned and unplanned outages of **elements** on the Facilities Notification List and those multiple transmission **element** outages that may have an adverse impact on external energy transfers.

All outages to equipment listed in the Facilities Notification List and those multiple transmission **element** outages that may have an adverse impact on external energy transfers should be planned with as much advance notice as practical.

Normally, notification for outages on **elements** covered by this instruction will be submitted to the appropriate RC Areas at least two (2) working days prior to the time the **element** is to be taken out of service.

When an RC Area receives an outage notification from another RC Area, prompt attention will be given to the notification and appropriate comments rendered.

4.3.3 An RC Area will not normally remove from service any transmission **elements,** which might have a **reliability** impact on an RC Area without prior notification to and appropriate review by that RC Area. In the event of an **emergency** condition, each RC Area may take action as deemed appropriate. Other RC Areas should be notified immediately.

An RC Area will make every effort to reschedule routine (non-emergency) transmission outages that severely degrade the reliability of an adjacent RC Area or neighboring system.

4.3.4 Each RC Area will advise the other affected RC Areas of any **protection** outage associated with RC Area tie line facilities Coordination agreements may identify additional reporting requirements associated with **protection** outages.

5.0 Specific Communications

Conditions in an RC Area that may have an impact on another RC Area should be communicated in a clear and timely manner. Specific communications are conducted as follows:

5.1 Weekly

Each Thursday a conference call will be initiated by the NPCC Staff to discuss operations expected during the seven-day period starting with the following Sunday. Operations personnel from the NPCC RC Areas and, as necessary, adjacent RC Areas will participate. In advance of the conference call, each RC Area will prepare the data specified in Attachments A and B, and forward it to the NPCC Staff a minimum of one hour in advance of the scheduled call. The completed "NPCC Weekly Conference Call Generating **Capacity** Worksheet," Attachment B, together with the list of "Twelve Weeks Projections of Net Margins," will be forwarded to the conference call participants by the NPCC Staff.

Each RC will review its weekly **capacity** margins for the next twelve week period. If a deficiency or light **load** condition is identified, the RC will identify the cause of the deficiency or light **load** condition and discuss proposed mitigation measures.

The NPCC Staff will prepare Conference Call Notes that will be forwarded to the conference call participants and members of the TFCO by the following Friday afternoon.

Items of particular concern that should be addressed during the weekly conference call are described in Attachment C.

5.2 Emergency Preparedness Conference Call

Whenever adverse system operating or weather conditions are expected, any RC Area may request the NPCC Staff to arrange an Emergency Preparedness Conference Call (NPCC Document C-01) to discuss operating details with appropriate operations management personnel from the NPCC RC Areas and neighboring systems.

5.3 Daily Conference Calls

Each of the NPCC Reliability Coordinator Area control rooms participate in a regularly scheduled daily conference call. The goal of this call is to alert NPCC Reliability Coordinators of any potential emerging problems. Subjects for discussion are limited to credible events which could impact the ability of a

Reliability Coordinator to serve its **load** and meet its operating reserve obligations, or which would impose a burden to the Interconnection.

Procedure for Operational Planning Coordination – Attachment A

Load and Capacity Table Instructions
and
Generating Capacity Worksheet Instructions

Week Beginning	The seven day period for which data is to be reported is defined as starting with the Sunday following the conference call through the following Saturday.
Installed Generating Capacity (Line Item 1)	Include all available **generation** at its maximum demonstrated capability for the appropriate seasonal capability period.
Other Generating Capacity(Line Item 2)	Include all available **generation** not included in Item#1. This item includes, but is not limited to, co-generators, small power producers and all other non-utility electricity producers, such as exempt wholesale generators who sell electricity.
Firm Purchases (Line Item 3)	Include only those transactions where **capacity** is delivered. Exclude "energy only" transactions.
Firm Sales (Line Item 4)	Include only those transactions where **capacity** is delivered. Exclude "energy only" transactions.
Net Capacity (Line Item 5)	Add Installed Generating **Capacity** and Firm Purchases. Subtract Firm Sales. (Line 1+Line 2-Line3)
Peak Load Forecast (Line Item 6)	The peak **load** forecast along with the day during which the peak is expected to occur should be the best estimate of the RC Area's maximum peak **load** exposure anticipated for the week reported.
Available Reserve (Line Item 7)	Subtract Peak **Load** Forecast from Net **Capacity**. (Line 4-Line5.)
Demand Side Management (Line Item 8)	Include only maximum capability which can be obtained by operator initialization within four (4) hours.

Attachment A (continued)	
Known Unavailable Capacity (Line Item 9)	Include all known outages, as well as those deratings or unit outages presently forced out, unavailable, on extended cold standby or which are anticipated to remain out of service. This would also include **capacity** unavailable due to transmission constraints.
Net Reserve (Line Item 10)	Available Reserve plus **Demand** Side Management minus Known Unavailable **Capacity**. (Line 6+Line 7-Line 8)
Required Operating Reserve (Line Item 11)	The methodology used by each RC Area in calculating operating reserves should, at a minimum, meet the requirements of NPCC Directory # 5, "Reserve." Methodologies differing from the Directory #5 requirements should be clarified in Attachment B, "NPCC Weekly Conference Call Generating **Capacity** Worksheet," under the tab for "Operating Reserve."
Gross Margin (Line Item 12)	Subtract Required Operating Reserve from Net Reserve. (Line 9-Line 10)
Unplanned Outages (Line Item 13)	Estimate the amount of generating **capacity** which will be unavailable. This quantity should be based on historical averages for forced outages and deratings.
Net Resource Capacity Margin (Line Item 14)	Subtract Unplanned Outages from Gross Margin. A positive value reflects surplus reserve. A negative value reflects a deficiency. (Line 11-Line 12)
Forecast High / Low Temperatures and Days (Line Item 15)	Include the expected high and low temperatures for the RC **Area** for the week, and indicate the day on which they are expected to occur.

Attachment A (continued)	
Seasonal High / Low Temperatures (Line Item 16)	Include the expected high and low forecast seasonal temperatures for the RC **Area**.
Minimum Load Forecast (Line Item 17)	The minimum **load** forecast, indicating the day on which it is expected to occur should be the best estimate of the RC Area's minimum **load** exposure anticipated for the week reported.
Minimum Resources (Line Item 18)	The Minimum **Resources** are the Reliability Coordinator **Area's** total expected on-line generator minimum output capability and must-take purchases.
Light Load Margin (Line Item 19)	Subtract Minimum **Resources** from Minimum **Load** Forecast. A negative number indicates a light **load** condition. (Line 17-Line 18)

Procedure for Operational Planning Coordination – Attachment B

NPCC Weekly Conference Call Generating Capacity Worksheet

The "NPCC Weekly Conference Call Generating **Capacity** Worksheet" is an active spreadsheet used each week to assist in the calculation of the data discussed during the weekly conference call. A blank template is available from the NPCC office.

Procedure for Operational Planning Coordination - Attachment C

CONDITIONS FOR DISCUSSION

Items of particular concern that should be discussed during a conference call can include, but are not limited to, the following:

- anticipated weather;
- largest first and second contingencies;
- operating reserve requirements and expected available operating reserve;
- **capacity** deficiencies;
- potential fuel shortages or potential supply disruptions which could lead to energy shortfalls;
- light **load** margins;
- general and specific voltage conditions throughout each system or RC Area;
- status of short term contracts and other scheduled arrangements, including those that impact on operating reserves;
- additional capability available within twelve hours and four hours;
- generator outages that may have a significant impact on an adjacent RC **Area** or neighboring system;
- transmission outages that may have an adverse impact on external energy transfers;
- potential need for emergency transfers;
- expected transfer limits and limiting elements;
- a change or anticipated change in the normal operating configuration of the system, such as the temporary modification of relay **protection** schemes so that the usual and customary levels of **protection** will not be provided, or the arming of **special protection systems** not normally armed, or the application of abnormal operating procedures; and
- update of the abnormal status of NPCC Type I **special protection systems** forced out of service

Attachment D

NPCC Facilities Notification List

Attachment D is not publicly available due to the confidential nature of the information presented.

Appendix G - Procedures for Inter Reliability Coordinator Area Voltage Control

1.0 Introduction

This Procedure provides general principles and guidance to Reliability Coordinators and Transmission Operators for effective inter- Transmission Operator Area voltage control, consistent with the NPCC, Directory #1, "Design and Operation of the **Bulk Power System**". Specific methods to implement this Procedure may vary among Reliability Coordinators and Transmission Operators, depending on local requirements. Coordinated inter- Transmission Operator Area voltage control is necessary to regulate voltages to protect equipment from damage and prevent voltage collapse. Coordinated voltage regulation reduces electrical losses on the network and lessens equipment degradation. Local control actions are generally most effective for voltage regulation. Occasions arise when adjacent Reliability Coordinators and Transmission Operators can assist each other to compensate for deficiencies or excesses of **reactive power** and improve voltage profiles and system security.

2.0 Principles

Each Reliability Coordinator and Transmission Operator operates, in accordance with NPCC, Directory #1, "Design and Operation of the **Bulk Power System**" criteria, their own individual or joint operating policies, procedures and applicable interconnection agreements. Adjacent Reliability Coordinators and Transmission Operator should be familiar with the respective criteria and procedures of their neighboring Reliability Coordinators and Transmission Operator Areas, and should mutually agree upon procedures for inter- Transmission Reliability Coordinator and Operator Area voltage control.

In the event the system state changes to a condition that requires a voltage or reactive corrective action, the Reliability Coordinator and Transmission Operator for the Area in which the condition is originating from should immediately take corrective action. If the corrective control actions are ineffective, or the Reliability Coordinator and Transmission Operator for the Area have insufficient reactive **resources** to control the problem, assistance may be requested from other Reliability Coordinators and Transmission Operator Areas.

Whether inter- Reliability Coordinator and Transmission Operator **Area** voltage control is carried out through specific or general procedures, the following should be considered and implemented if applicable:

2.1 To effectively coordinate voltage control, location and placement of metering for **reactive power resources** and voltage controller status should be the same between adjacent Reliability Coordinators and Transmission Operator Areas;

2.2 the availability of **voltage regulating transformers** in the proximity of **tie lines**;

2.3 voltage levels, limits, and regulation requirements for stations on either side of an inter- Reliability Coordinator and Transmission Operator **Area** interface;

2.4 the circulation of **reactive power** (export at one tie point in exchange for import at another);

2.5 **tie line** reactive losses as a function of active **power** transfer;

2.6 the sharing of the reactive requirements of **tie lines** and series regulating equipment (either equally or in proportion to line lengths, etc.);

2.7 the transfer of **reactive power** from one Reliability Coordinator and Transmission Operator Area to another

2.8 reactive **reserve** of on-line generators;

2.9 shunt reactive device availability and switching strategy;

2.10 **static VAR compensator** availability, reactive **reserve**, and control strategy;

2.11 each Reliability Coordinator and Transmission Operator Area should anticipate voltage trends and initiate corrective action in advance of critical periods of heavy and light **loads.**

2.12 Each Reliability Coordinator and Transmission Operator Area should maintain a mix of static and dynamic **resources**, including reactive **reserves**

3.0 Procedure for Triennial Monitoring and Reporting of Inter-Area Voltage Control

3.1 On, or shortly before, the first of July, the Task Force Coordination of Operations (TFCO) Secretary will write to each TFCO member, requesting a written response by the end of July in the form of:

a) A copy of any new or revised procedures, principles, or understandings (such as minutes of an operating committee meeting between Reliability Coordinators and Transmission Operator Areas) between the reporting Reliability Coordinator and adjacent Reliability Coordinators, or,

b) a response indicating no change to existing procedures, principles, or understandings currently on file at NPCC.

3.2 The TFCO Secretary will summarize the responses and will forward it to TFCO members at least two weeks prior to the October TFCO meeting.

3.3 Following TFCO review and acceptance of the responses, the TFCO Chairman will forward the summary to the Chairman of the Reliability Coordinating Committee (RCC) for informational purposes. This will normally be forwarded three weeks prior to the next regularly scheduled RCC meeting.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**
2. **Number:** **TPL-001-4**
3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.
4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall 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. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. 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.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
* **P7** Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [1] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Double Circuit Contingencies:
A&B, A&C, B&D, C&D

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.[11]
   ** b. Loss of all Transmission lines on a common Right-of-Way[11].
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a generating station.
   e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
   a. Loss of two generating stations resulting from conditions such as:
      i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
      ii. Loss of the use of a large body of water as the cooling source for generation.
      iii. Wildfires.
      iv. Severe weather, e.g., hurricanes, tornadoes, etc.
      v. A successful cyber attack.
      vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
   b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   e. 3Ø internal breaker fault.
   f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. 2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. 3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss. 4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service. 5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. 6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground. 7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point. 8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker. 9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed 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. 10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing. * 11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less. 12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction. 13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, &

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. .The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
    a. The estimated number and type of customers affected

   b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community
3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual cr joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

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	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	

* FOR INFORMATIONAL PURPOSES ONLY *

Enforcement Dates: Standard TPL-001-4 — Transmission System Planning Performance Requirements

United States

Standard	Requirement	Enforcement Date	Inactive Date
TPL-001-4	R1.	01/01/2015	
TPL-001-4	R2.	01/01/2016	
TPL-001-4	R3.	01/01/2016	
TPL-001-4	R4.	01/01/2016	
TPL-001-4	R5.	01/01/2016	
TPL-001-4	R6.	01/01/2016	
TPL-001-4	R7.	01/01/2015	
TPL-001-4	R8.	01/01/2016	

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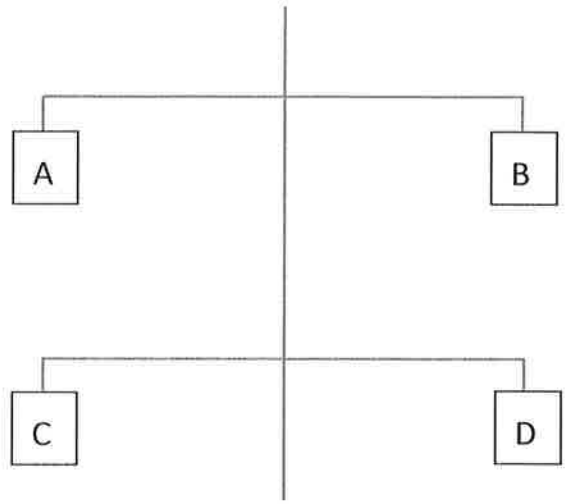
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