NPCC, Inc.

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NORTHEAST POWER COORDINATING COUNCIL, INC.

TFCP / TFCO Changes
RCC Approval
Clean

May 17, 2024

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
3	3/05/2020	Table 3 Errata	Errata
4	9/9/2020	Conforming Changes -- A-10 Exclusions, C-33 Retired, Appendix A Updated.	Revised
5	12/06/2022	Footnotes added to Tables #1, #2, and #3	Revised
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Appendix H - Technical Rationales

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.

For the purpose of the application of this Directory, **bulk power system elements** are those **elements** on the **Bulk Power System** List except for those **elements** specifically designated as exclusions for Directory#1 applicability.

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. Appendix F provides guidance for Operational Planning Coordination.

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, **resource** variability, 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. The corrective action plans shall be reviewed in subsequent annual Transmission Reviews for continued validity and implementation status of identified system facilities and **operating procedures**.

~~Special Protection Systems~~

~~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.~~**Remedial Action Schemes**

R12 Each Planning Coordinator shall perform an evaluation of each **RAS** within its planning area as part of its **Area** Transmission Review in accordance with Directory #7.

~~R12~~

~~**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 shall be updated and ~~submit the list~~submitted 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*~~***Remedial Action Schemes*** (NPCC Directory #7~~)~~)
*Classification of **Bulk Power System Elements*** (A-10)

Table 1

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

Category	Contingency ~~events~~Events[2] Simulate the removal of all **elements** that **protection systems**, including ~~**Special Protection Systems**~~**Remedial Action Schemes**, are expected to automatically disconnect for each event that involves an ~~AC~~ac **fault.**	**Fault** ~~type~~Type (permanent) On the listed **elements** where applicable	Performance ~~requirements~~Requirements
I **Single Event**	1. **Fault** on any of the following: ~~3~~ a. transmission circuit b. transformer c. shunt device d. generator ~~e.~~ bus section e.	Three-phase **fault**[4] with **normal fault clearing**	

[2] **Contingency** ~~Events~~events #4, #5, #8 and #9: A breaker failure **contingency** that involves an **element** excluded from Directory #1 applicability is to be evaluated, provided that the **contingency** also involves a non-excluded **bulk power system element**.

~~[3] When free standing or column-type current transformers (CTs) are provided on only one side of a live tank circuit breaker protecting a transmission element, a fault between the breaker and the CTs may experience delayed fault clearing depending on the local arrangement of protection zone (Directory #4 further discusses this in Sections 5.2.4 and 5.2.5). Three-phase fault testing between the CTs and the breaker is not required, contingency testing shall be conducted by applying a phase to ground fault on the short section between the CTs and the breaker.~~

~~Footnote #3 Rationale:~~
~~1) The presence of free standing or column-type current transformers (CTs) on only one side of live tank breakers protecting a transmission element is considered as an acceptable design.~~
~~2) The usual protection design in these cases, per Directory 4 Section 5.2.5, includes a frame ground protection scheme and a breaker failure protection scheme, with neither needing to be duplicated. A phase to ground fault will typically be cleared by the frame ground scheme (e.g., system A) before the breaker failure protection scheme (e.g., system B) operates.~~
~~3) When frame ground protection is utilized, any phase to ground fault between the CTs and the live tank breaker is assumed to flash over to the equipment frame at fault inception.~~
~~4) Since frame ground protection does not detect multiphase faults that do not involve ground, a three-phase fault occurring on the short section between the CTs and the live tank breaker will typically be cleared by breaker failure protection, resulting in a delayed fault clearing. However, such a fault is considered a very low probability event, due to the typical distance between the CTs and the live tank breaker.~~

[4] If an entity becomes aware of the loss of an **element** without a **fault** or a different **fault** type (phase to ground, phase-to-phase and phase-phase-ground) that would result in a more severe system response, that entity must demonstrate that the performance requirements are also met for such an event. See Technical Rationale 2 in Appendix H for additional details.

Category	Contingency ~~events~~Events[2] Simulate the removal of all **elements** that **protection systems**, including ~~Special Protection Systems~~Remedial Action Schemes, are expected to automatically disconnect for each event that involves an ~~AC~~ac **fault.**	Fault ~~type~~Type (permanent) On the listed **elements** where applicable	Performance ~~requirements~~Requirements
	~~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~~ 2.	No **fault**	i~~.~~ to viii
	3. Loss of single pole of a direct current facility	No **fault**	
	4. **Fault** on any of the following:[5] 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[6]	Phase to ground **fault,** with **normal fault clearing**	

~~[5] When free standing or column-type current transformers (CTs) are provided on only one side of a live tank circuit breaker protecting a transmission element, a fault between the breaker and the CTs may experience delayed fault clearing depending on the local arrangement of protection zones. It is not required to perform contingency event #4 testing with the initiating fault on the short section between the CTs and the breaker.~~

~~Footnote #4 Rationale:~~
~~1) The presence of free standing or column-type current transformers (CTs) on only one side of live tank breakers protecting a transmission element is considered as an acceptable design.~~
~~2) A fault on the short section between a free-standing CT and live-tank breaker followed by the failure of a circuit breaker is considered a very low-probability event.~~

[6] A **fault** on a circuit breaker includes a **fault** at a location on, or in the immediate vicinity of, the circuit breaker that must be cleared by **protection** on both sides of the circuit breaker, including:

a. A **fault** physically internal to the circuit breaker

Category	**Contingency ~~events~~Events**[2] Simulate the removal of all **elements** that **protection systems**, including **~~Special Protection Systems~~Remedial Action Schemes**, are expected to automatically disconnect for each event that involves an ~~AC~~ac **fault.**	**Fault ~~type~~Type** (permanent) On the listed **elements** where applicable	Performance ~~requirements~~Requirements
	6. Simultaneous **fault** on two adjacent transmission circuits on a multiple circuit tower.[7]	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~~RAS 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**	

b. A **fault** within the region of **protection** zone overlap that encompasses the circuit breaker
c. When free standing or column-type current transformers (CTs) are provided on only one side of a live tank circuit breaker protecting a transmission **element**, a **fault** between the breaker and the CTs

Faults at locations covered by **contingency** event #5 that could be interpreted to also be covered by another **contingency** event (e.g. **contingency** events #1 or #4) need only to be tested under **contingency** event #5. See Technical Rationale 1 in Appendix H for additional details.

[7] A multiple circuit tower **contingency** that involves an **element** excluded from Directory #1 applicability is to be evaluated, provided that the **contingency** also involves a non-excluded **bulk power system element.**

Category	**Contingency ~~events~~Events**[2] Simulate the removal of all **elements** that **protection systems**, including **~~Special Protection Systems~~Remedial Action Schemes**, are expected to automatically disconnect for each event that involves an ~~AC~~ac **fault.**	**Fault ~~type~~Type** (permanent) On the listed **elements** where applicable	Performance ~~requirements~~Requirements
	9. The failure of a circuit breaker to operate when initiated by a ~~SPS~~RAS 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**	i~~.~~ to viii

Category	Contingency ~~events~~Events[2] Simulate the removal of all **elements** that **protection systems**, including ~~**Special Protection Systems**~~**Remedial Action Schemes**, are expected to automatically disconnect for each event that involves an ~~AC~~ac **fault.**	**Fault** ~~type~~Type (permanent) On the listed **elements** where applicable	Performance ~~requirements~~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**~~.~~, and:

a. Any cascading that causes the loss of small or radial portions of a system must be demonstrably contained within an **Area** or a defined portion of the system that crosses Areas[8].

b. The net loss of source or loss of load, must not exceed a threshold of acceptability established by the Area(s), and that acceptability threshold must not exceed an **Area's** applicable threshold used for the classification of **BPS elements**[9].

[8] Containment of cascading can be determined by examining sequential tripping caused by exceeding **stability** limits, voltage limits and/or transmission **element** loading. When cascading crosses to a neighboring **Area** or results in a neighboring **Area** being isolated from the rest of its **interconnection**, the affected **Area** shall be consulted to determine the severity of the impact on the performance of the system in the neighboring **Area**. All impacted Areas must agree that the cascading is contained.

[9] Section 3.3 of *Regional Reliability Reference Criteria A-10 Classification of **Bulk Power System Elements*** describes the development of the net loss of source and/or **load** criteria for each **Area**. Simulations shall reflect loss of conventional **generation** and inverter-based **resources** based on actions resulting from control and protective functions, or loss of synchronism, as applicable.

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**~~any dynamic oscillatory response shall be clearly positively damped, with due regard to successful and unsuccessful **reclosing** (excluding **manual 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~~circuits share common structures for ~~station entrance and exit purposes and if they do not exceed five towers at each station~~a cumulative length of one mile or less, then this condition is an acceptable risk and therefore can be excluded. For instances where single (non-consecutive) structures are shared along the route, half of the length of the longest single span attached to the multiple circuit tower structure should be included for the purpose of determining the cumulative length. 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.

viii.

Table 2

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

Category	Contingency ~~events~~Events[10] Simulate the removal of all **elements** that **protection systems**, including ~~**Special Protection Systems**~~**Remedial Action Schemes**, are expected to automatically disconnect for each event that involves an ~~AC~~ac **fault.**	**Fault** ~~type~~Type (permanent) and/or condition applied On the listed **elements** where applicable	Performance ~~to be assessed~~Assessments
Extreme Contingency	1. Loss of the entire capability of a generating station.	No ~~**Fault**~~**fault**	i, ii, iii
	2. Loss of all transmission circuits (all voltage levels) emanating from a generating station, switching station, substation~~,~~ or dc terminal.	No ~~**Fault**~~**fault**	
	3. Loss of all transmission circuits ~~on~~that share a common right-of-way.	No ~~**Fault**~~**fault**	
	4. **Fault** on of any of the following~~[11]~~:: a. transmission circuit b. transformer c. shunt device d. generator	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~~ (with due regard to successful and unsuccessful **reclosing**~~.)~~, excluding **manual reclosing**).	

[10] **Contingency** ~~Events~~events #4, #5: A breaker failure **contingency** that involves an **element** excluded from Directory #1 applicability is to be evaluated, provided that the **contingency** also involves a non-excluded **bulk power system element**.

~~[11] When free standing or column-type current transformers (CTs) are provided on only one side of a live tank circuit breaker protecting a transmission element, a fault between the breaker and the CTs may experience delayed fault clearing depending on the local arrangement of protection zones. It is not required to perform contingency event #4 testing with the initiating fault on the short section between the CTs and the breaker.~~

~~Footnote #7 Rationale:~~
~~1) The presence of free standing or column-type current transformers (CTs) on only one side of live tank breakers protecting a transmission element is considered as an acceptable design.~~
~~2) A fault on the short section between a free-standing CT and live-tank breaker followed by the failure of a circuit breaker is considered a very low-probability event.~~

Category	Contingency ~~events~~Events[10] Simulate the removal of all **elements** that **protection systems**, including ~~**Special Protection Systems**~~**Remedial Action Schemes**, are expected to automatically disconnect for each event that involves an ~~AC~~ac **fault.**	**Fault** ~~type~~Type (permanent) and/or condition applied On the listed **elements** where applicable	Performance ~~to be assessed~~Assessments
	e. bus section		
	5. -**Fault** on a circuit breaker[12]	Three-phase **fault**, with **normal fault clearing**	
	6. Sudden loss of a large **load** or major **load** center.	No ~~**Fault**~~**fault**	
	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**~~**RAS**, 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**~~**RAS** for an event or condition for which it was not intended to operate.	No ~~**Fault**~~**fault**	
	10. Sudden loss of fuel delivery system to multiple plants, (e.g.~~,~~. gas pipeline **contingencies**).	No ~~**Fault**~~**fault.**	
	11. Any additional extreme **contingencies** identified by each Planning Coordinator Area.	**Fault** applied as necessary.	
Extreme System	**Contingency** events listed in Table 1, Category I, Single Event	Peak **load** conditions resulting from extreme weather.	i (b, c), ii, iii

[12] A **fault** on a circuit breaker includes a **fault** at a location on, or in the immediate vicinity of, the circuit breaker that must be cleared by **protection** on both sides of the circuit breaker, including:

a. A **fault** physically internal to the circuit breaker only if the construction of the circuit breaker could result in an internal **fault** that crosses multiple phases.
b. When free standing or column-type current transformers (CTs) are provided on only one side of a live tank circuit breaker protecting a transmission **element**, a phase to ground **fault** between the breaker and the CTs

Faults at locations covered by **contingency** event #5 that could be interpreted to also be covered by another **contingency** event (e.g. **contingency** event #4) need only to be tested under **contingency** event #5. See Technical Rationale 1 in Appendix H for additional details.

Category	Contingency ~~events~~Events[10] Simulate the removal of all **elements** that **protection systems**, including **~~Special Protection Systems~~Remedial Action Schemes**, are expected to automatically disconnect for each event that involves an ~~AC~~ac **fault.**	**Fault** ~~type~~Type (permanent) and/or condition applied On the listed **elements** where applicable	Performance ~~to be assessed~~Assessments
Conditions		Generating unit(s) fuel shortage (e.g~~.,~~., gas supply adequacy or low hydro) under normal weather peak conditions	i (c), ii, iii

Performance Assessment for the contingencies defined in Table 2:

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

   a. transfers within or between Transmission Planner and Planning Coordinator Areas should be studied at ~~values~~or above the 75th percentile of flow (in other words, flows not ~~expected to be~~ exceeded more than 25% of the time~~. –~~) based on all hours of the year.

   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~~changes to design or operating practices to address such **contingencies** shall be conducted.

Table 3

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

	Contingency ~~events~~Events[13] Simulate the removal of all **elements** that **protection systems**, including ~~**Special Protection Systems**~~**Remedial Action Schemes**, are expected to automatically disconnect for each event that involves an ~~AC~~ac **fault**.	**Fault** ~~type~~Type (permanent) On the listed **elements** where applicable	Performance ~~requirements~~Requirements	
			Normal Transfer Capability	**Emergency Transfer Capability** (~~Only~~only after an **Emergency** is identified)
	1. **Fault** on any of the following:[14] a. transmission circuit b. transformer	Three-phase **fault**[15], with **normal fault clearing**	i, ii, iii, iv, v, vi, vii, ix, x	i, ii, iii, iv, v, vi, vii, ix, xi

[13] **Contingency** ~~Events~~events #4, #5, #8 and #9: A breaker failure **contingency** that involves an **element** excluded from Directory #1 applicability is to be evaluated, provided that the **contingency** also involves a non-excluded **bulk power system element**.

~~[14] When free standing or column-type current transformers (CTs) are provided on only one side of a live tank circuit breaker protecting a transmission element, a fault between the breaker and the CTs may experience delayed fault clearing depending on the local arrangement of protection zone (Directory #4 further discusses this in Sections 5.2.4 and 5.2.5). Three-phase fault testing between the CTs and the breaker is not required, contingency testing shall be conducted by applying a phase to ground fault on the short section between the CTs and the breaker.~~

~~Footnote #9 Rationale:~~
~~1) The presence of free standing or column-type current transformers (CTs) on only one side of live tank breakers protecting a transmission element is considered as an acceptable design.~~
~~2) The usual protection design in these cases, per Directory 4 Section 5.2.5, includes a frame ground protection scheme and a breaker failure protection scheme, with neither needing to be duplicated. A phase to ground fault will typically be cleared by the frame ground scheme (e.g., system A) before the breaker failure protection scheme (e.g., system B) operates.~~
~~3) When frame ground protection is utilized, any phase to ground fault between the CTs and the live tank breaker is assumed to flash over to the equipment frame at fault inception.~~
~~4) Since frame ground protection does not detect multiphase faults that do not involve ground, a three-phase fault occurring on the short section between the CTs and the live tank breaker will typically be cleared by breaker failure protection, resulting in a delayed fault clearing. However, such a fault is considered a very low probability event, due to the typical distance between the CTs and the live tank breaker.~~

[15] If an entity becomes aware of a no **fault** or a different **fault** type (phase to ground, phase-to-phase and phase-phase-ground) that would result in a more severe

	c. shunt device d. generator e. bus section			
	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**	~~i,ii,iii,iv,v,vi,vii, viii, ix,x~~	**Contingency** ~~Events 4 through 9 do~~event #1e does not apply after an **emergency** is identified . ~~**Contingency** Events 4~~

system response, that entity must demonstrate that the performance requirements are also met for such an event. See Technical Rationale 2 in Appendix H for additional details.

			~~i,ii,iii,iv,v,vi,vii, viii, ix,x~~	~~through 9 do not apply after an emergency is identified~~
	4. **Fault** on any of the following:[16] a. transmission circuit b. transformer c. shunt device d. generator ~~e.~~ bus section e.	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 #9 do not apply after an **emergency** is identified.

~~[16] When free standing or column-type current transformers (CTs) are provided on only one side of a live tank circuit breaker protecting a transmission element, a fault between the breaker and the CTs may experience delayed fault clearing depending on the local arrangement of protection zones. It is not required to perform breaker failure contingency testing with the initiating fault on the short section between the CTs and the breaker.~~
~~Footnote #10 Rationale:~~
~~1) The presence of free standing or column-type current transformers (CTs) on only one side of live tank breakers protecting a transmission element is considered as an acceptable design.~~
~~2) A fault on the short section between a free-standing CT and live-tank breaker followed by the failure of a circuit breaker is considered a very low-probability event.~~

			i, ii, iii, iv, v, vi, vii, viii, ix, x	**Contingency** events #4 through #9 do not apply after an **emergency** is identified.
	5. **Fault** on a circuit breaker [17]	Phase to ground **fault** with **normal fault clearing**		
	~~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.[18]	Phase to ground **faults** on different phases of each circuit with **normal fault clearing**		

[17] A **fault** on a circuit breaker includes a **fault** at a location on, or in the immediate vicinity of, the circuit breaker that must be cleared by **protection** on both sides of the circuit breaker, including:

a. A **fault** physically internal to the circuit breaker
b. A **fault** within the region of **protection** zone overlap that encompasses the circuit breaker
c. A **fault** between the breaker and a free standing or column-type current transformer (CT) when CTs are provided on only one side of a live tank circuit breaker protecting a transmission **element**

Faults at locations covered by **contingency** event #5 that could be interpreted to also be covered by another **contingency** event (e.g. **contingency** events #1 or #4) need only to be tested under **contingency** event #5. See Technical Rationale 1 in Appendix H for additional details.

[18] A multiple circuit tower **contingency** that involves an **element** excluded from Directory #1 applicability is to be evaluated, provided that the **contingency** also involves a non-excluded **bulk power system element**.

	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~~RAS 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**		
	9. The failure of a circuit breaker to operate when initiated by a ~~SPS~~RAS 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.** Any cascading that causes the loss of small or radial portions of a system must be demonstrably contained within an **Area** or a defined portion of the system that crosses Areas[19].

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[19] Containment of cascading can be determined by examining sequential tripping caused by exceeding **stability** limits, voltage limits and/or transmission **element** loading. When cascading crosses to a neighboring **Area** or results in a neighboring **Area** being isolated from the rest of its **interconnection**, the affected **Area** shall be consulted to determine the severity of the impact on the performance of the system in the neighboring **Area**. All impacted Areas must agree that the

iii. Individual Reliability Coordinator Areas shall be operated in a manner such that ~~Contingencies~~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 and any dynamic oscillatory response shall be clearly positively damped, 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~~circuits share common structures for ~~station entrance and exit purposes, and if they do not exceed five towers at each station~~a cumulative length of one mile or less, then this condition is an acceptable risk and therefore can be excluded. For instances where single (non-consecutive) structures are shared along the route, half of the length of the longest single span attached to the multiple circuit tower structure should be included for the purpose of determining the cumulative length. 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.**~~**Remedial Action Scheme.** 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.

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cascading is contained. Additionally, simulations shall reflect loss of conventional **generation** and inverter-based **resources**, based on actions resulting from control and protective functions, or loss of synchronism, as applicable.

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:

- EOP-011 Emergency Operations
- FAC-011 System Operating Limits Methodology for the Operating Horizon
- IRO-002 Reliability Coordination Monitoring and Analysis
- IRO-14 Coordination Among Reliability Coordinators
- MOD-25 Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability
- MOD-31 Demand and Energy Data
- MOD-32 Data for Power System Modelling and Analysis
- TOP-001 Transmission Operations
- TOP-002 Operations Planning
- TOP-003 Operational Reliability Data
- TPL-001 Transmission System Planning Performance Requirements
- VAR-001 Voltage and Reactive Control

Appendix B - Guidelines and Procedures for NPCC Transmission Reviews

1.0 Introduction and Purpose of Transmission Review

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~~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~~2.0 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~~3.0 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.

The analyses described above for a Comprehensive Review or Intermediate Review may be supported by other studies if they are five calendar years old or less and a technical rationale can be provided for the reliance on the studies.

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. As part of the proposal the Planning Coordinator shall provide the technical rationale for reliance on any other studies. 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)1.1 Introduction~~

- ~~Reference the most recent Area Comprehensive Review and any subsequent Intermediate or Interim reviews as appropriate.~~

~~1.1.1. 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.~~

~~1.1.1. Include maps and one-line diagrams of the system showing proposed changes as necessary.~~

~~1.1.1. Describe the **demand** levels to be studied, according to the range of forecast system **demands.**~~

- ~~Identify projected firm transfers and interchange schedules.~~

~~b)1.1Present 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)1.1Steady 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.~~

~~1.1.1. 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)1.1Stability 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)~~1.1 ~~**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**.~~

1.1.1. ~~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)1.1Extreme 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)~~1.1 ~~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.~~

~~j) Overview Summary of System Performance for Year Studied~~

~~6.0 Format of Presentation - Interim Review~~

~~a)~~1.1~~Introduction of Interim Review~~

~~b)~~1.1~~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.~~

~~•~~1.1.1. ~~**Load** Forecast~~

~~•~~1.1.1. ~~**Generation Resources**~~

- ~~Bulk Power System elements~~

~~1.1.1. Transmission Facilities~~

- ~~Special Protection Systems~~

- ~~Exclusions~~

~~d)1.1Brief Impact Assessment and Overview Summary~~

~~1.1.1. 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~~4.0 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.~~in Section 5.0 below. 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,~~(as described in Section 3.0), along with appropriate excerpts from those studies~~.~~ as necessary.

The documentation required for an Interim Review should be in the form of a short summary report (normally not exceeding ~~5~~five pages), containing a description of system changes and a brief assessment on their impact on the **reliability** of the interconnected **bulk power system**~~.~~. The format of the report is described in Section 6.0.

5.0 Format of Report – Comprehensive and Intermediate Review

5.1 Introduction

5.1.1. Reference the most recent **Area** Comprehensive Review and any subsequent Intermediate or Interim Reviews as appropriate.

5.1.2. Provide a status update of previously identified corrective action plans.

5.1.3. Describe the type and scope of this review.

5.1.4. Provide an overview of the existing and planned **bulk power system** facilities and **Remedial Action Schemes (RAS)** included in this review and discuss changes in system facilities, **bulk power system elements**, **RAS,** and **loads** since the most recent Comprehensive Review.

5.1.5. Include maps and one-line diagrams of the system showing proposed changes as necessary.

5.1.6. Describe the **demand** levels to be studied, according to the range of forecast system **demands.**

5.1.7. Identify projected firm transfers, interchange schedules and applicable transfer limits within and between Planning Coordinator Areas.

5.2 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**.

5.3 Steady State Assessment

5.3.1. Present the **load** model, power factor, **demand** side management, distributed energy **resources** (DER) and other modelling assumptions used in the analysis. Discuss the methodology used in voltage assessments.

5.3.2. Provide a rationale for the **contingencies** selected for evaluation.

5.3.3. Provide case summary information that includes the **generation** dispatch conditions and flows on major inter-**Area** and intra-**Area interfaces**.

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

5.3.5. Present the results of thermal and voltage performance for the planned **bulk power system**.

5.3.6. Document the corrective action plan(s) developed to achieve conformance with NPCC Directory #1.

5.4 Stability Assessment

5.4.1. Present the **load** modelling, DER modelling, and other modelling assumptions used in the analysis.

5.4.2. Provide case summary information that includes the **generation** dispatch conditions and flows on major inter-**Area** and intra-**Area interfaces**.

5.4.3. Provide a rationale for the **contingencies** selected for evaluation including the nature of the **fault** applied, **elements** switched, and **fault** clearing times.

5.4.4. Document the effects of the **contingencies** that produce more severe system impacts including pertinent system response metrics that may include plots of angles versus time for significant machines, response of significant **real power** and **reactive power** control devices including inverter-based **resources**, the voltage at significant buses, **interface** flows, and loss of **load** and/or source.

5.4.5. Document the corrective action plan(s) developed to achieve conformance with NPCC Directory #1.

5.5 **Fault** Current Assessment

5.5.1. Present the methodology and assumptions used in the **fault** current assessment.

5.5.2. Present instances where **fault** levels exceed equipment capabilities.

5.5.3. Document corrective action plan(s) developed to achieve conformance with NPCC Directory #1.

5.6 Extreme **Contingency** Assessment (see also Appendix C Procedure for Testing and Analysis of Extreme Contingencies)

5.6.1. Present the scope of the analyses including a description of the system conditions assessed.

5.6.2. Provide a rationale for the extreme **contingencies** selected for evaluation.

5.6.3. Review the results for widespread cascading due to overloads, instability or voltage collapse caused by extreme **contingencies**.

5.6.4. Where extreme **contingency** assessment reveals serious consequences, include an evaluation of changes to design or operating practices to address such **contingencies**.

5.7 Extreme System Condition Assessment

5.7.1. Present the scope of the analyses including a description of the system conditions assessed.

5.7.2. Provide the rationale for the loss of fuel supply conditions selected for evaluation.

5.7.3. Provide a rationale for the **contingencies** selected for evaluation.

5.7.4. Where extreme condition assessment reveals serious consequences, include an evaluation of changes to design or operating practices to address the consequences.

5.8 Review of **Remedial Action Schemes (RASs)**

5.8.1. Present the scope of review that conforms with the Directory #7 requirement for **Area** Transmission Reviews. In accordance with **Requirement R12**, a Comprehensive Review should review all the existing, new, and modified **RASs** included in its transmission plan. An Intermediate Review may focus on the new and modified **RASs**, and just those existing **RASs** that may have been impacted by system changes since they were last reviewed.

5.8.2. Present results that demonstrate conformance with Directory #7 Section 6.4.

5.8.3. The Planning Coordinator should notify the RAS-entity of any identified deficiencies.

5.8.4. If the need for reclassification of a Limited Impact **RAS** is identified, the Planning Coordinator should notify the RAS-entity that a complete review of the **RAS** should be made, as per the Procedure for NPCC Review of New or Modified ***Bulk Power System Remedial Action Scheme (RAS)*** in Directory #7.

5.9 Review of Exclusions to the Directory#1 Criteria

5.9.1. 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.

5.10 Overview Summary of System Performance for Year Studied

6.0 Format of Report - Interim Review

6.1 Introduction of Interim Review

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

6.2.1. Provide a status update of previously identified corrective action plans.

6.3 Changes in Facilities (Existing and Planned) and Forecasted System Conditions since the last Comprehensive Review.

6.3.1. **Load** Forecast

6.3.2. **Generation Resources**

6.3.3. **Bulk Power System Elements**

6.3.4. Transmission Facilities

6.3.5. **Remedial Action Schemes**

6.4 Brief Impact Assessment and Overview Summary

6.4.1. 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 Purpose of 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.

8.0 Format of Presentation

8.1 Presentation of comprehensive/intermediate review should include:

8.1.1. Introduction of comprehensive/intermediate review including the most recent **Area** Reviews, type and scope of this review, changes in system facilities, maps and/or one-lines showing the proposed changes, **load** levels to be studied, and projected firm transfers and **interchange schedules**.

8.1.1.1. Provide a status update of previously identified corrective action plans.

8.1.2. A discussion of qualified past studies that were used to meet the requirements of the **Area** Transmission Review.

8.1.3. Summary of steady state assessment including any performance requirement violations and proposed mitigation plans.

8.1.4. Summary of stability assessment including any performance requirement violations and proposed mitigation plans.

8.1.5. Summary of **fault** current assessment including instances where **fault** levels exceed equipment capabilities and measures to mitigate such occurrences.

8.1.6. Summary of extreme **contingency** assessment.

8.1.7. Summary of extreme system condition assessment.

8.1.8. Summary of **RAS** Review including any required reclassification of **RASs**.

8.2 Presentation of Interim Review should include:

8.2.1. Introduction of Interim Review including the most recent **Area** Reviews, changes in facilities and forecasted system conditions since the last Comprehensive Review.

8.2.1.1. Provide a status update of previously identified corrective action plans.

8.2.2. Overview summary of any assessment conducted or referenced as part of this review.

~~8.0~~9.0 Task Force Follow-Up Procedures

~~8.1~~9.1 ~~—~~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.~~9.1.1. 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.~~9.1.2. 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 Task Force on Coordination of Planning (TFCP~~.~~).

~~c.~~9.1.3. If the report is considered as complete and in full conformance with these Guidelines, TFSS will accept the report.

~~8.2~~9.2 — 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~~TFCP.

~~8.3~~9.3 — Upon completion of an **Area** Review, TFSS will report the results of the review to the ~~Task Force on Coordination of Planning~~TFCP. 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 (RCC) 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~~**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.

~~Modeling~~

3.0 Modelling 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 ~~**Special Protection Systems (SPS**~~**Remedial Action Schemes (RAS)**,
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 conventional **generation** and inverter-based **resources** based on tripping due to known or assumed **protection** systems, or loss of synchronism~~,~~ of one or more units, **generation** rejection or runback initiated by ~~SPS~~**RAS**, 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 in 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~~.~~, including Loss of Load Hours (LOLH), Expected Unserved Energy (EUE), and normalized-EUE metrics. 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~~most recent review, whether comprehensive or interim.

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~~criterion as stated in R4, 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~~criterion, 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, including LOLH, EUE, and normalized-EUE metrics.

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~~Reference MOD-025.

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~~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~~Modelling of Variable and Limited Energy Sources.

1.5 ~~Modeling~~Modelling 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~~Modelling 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~~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~~,~~ (TFCP), the latter ~~shall~~, as appropriate, will:

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 (RCC) whether the **Resource** Adequacy Review is suitable for approval.

1.4

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**~~**Remedial Action Scheme,** 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 (CEII) 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 **capacity** 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 Advance Planning of Transmission Facility Outages

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~~should minimize the duration of outages to facilities that impact inter-Reliability Coordinator Areas.

4.2 Facilities Notification List

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**~~**Remedial Action Scheme**.

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 **capacity** deficiency or light **load** condition is identified, the RC will identify the cause of the **capacity** 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~~ + Line 3 – Line 4)
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.)~~5 - Line 6)
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 - Line 9)
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-~~10 - Line ~~10~~11)
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-~~12 - Line ~~12~~13)
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~~Remedial Action Schemes (RAS) not normally armed, or the application of abnormal operating procedures; and
- update of the abnormal status of NPCC Type I ~~special protection systems~~RAS 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~~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~~ anticipation of voltage trends and ~~initiate~~initiation of corrective action in advance of critical periods of heavy and light **loads**~~.~~**;**

2.12 ~~Each Reliability Coordinator and Transmission Operator Area should maintain~~maintenance of 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.

Appendix H: Technical Rationales

Technical Rationale 1 – Treatment of faults in the immediate vicinity of the circuit breaker

A **fault** in the immediate vicinity of the circuit breaker is typically within the zone of **protection** of one of the transmission **elements** (line, transformer, bus section, etc.) associated with the breaker and is cleared in a similar time as a **fault** on the transmission **element**. However, when free standing or column-type current transformers (CTs) are provided on only one side of a live tank circuit breaker protecting a transmission **element**, a **fault** between the breaker and the CTs may only be cleared by opening transmission **elements** on both sides of the breaker. Functionally, this is very similar to an internal **fault** to a circuit breaker, where **fault** clearing requires the operation of **protection** associated with transmission **elements** on either side of the **faulted** breaker.

The presence of free standing or column-type current transformers on only one side of live tank breakers protecting a transmission **element** is considered as an acceptable design per Directory #4 Section 5.2.4. The usual **protection** design in these cases, per Directory #4 Section 5.2.5, includes a frame ground **protection** scheme and a breaker failure **protection** scheme, with neither needing to be duplicated. A phase to ground **fault** will typically be cleared by the frame ground scheme (e.g., system A) before the breaker failure **protection** scheme (e.g, system B) operates.

When frame ground **protection** is utilized, any phase to ground **fault** between the CTs and the live tank breaker is assumed to flash over to the equipment frame at **fault** inception. Since frame ground **protection** does not detect multiphase **faults** that do not involve ground, a three-phase **fault** occurring on the short section between the CTs and the live tank breaker will typically be cleared by breaker failure **protection**.

The probability of a three-phase **fault** inside a circuit breaker is extremely low and therefore in design criteria, only a phase to ground **fault** is tested when evaluating an internal **fault** in a circuit breaker. While the rationale for the low probability of a three-phase **fault** inside a circuit breaker is due to the construction of the device, the relative short length of the section between a free standing CT and live tank breaker is used as a basis to categorize a three-phase **fault** on this short section to be a low probability event. On this basis, for design criteria **contingency** testing in Tables 1 and 3 the testing of a **fault** on this short section is limited to a phase to ground **fault**. For extreme **contingency** testing, of **faults** on a circuit breaker, there are two conditions where a three-phase **fault** need not be considered:

- A **fault** physically internal to the circuit breaker only if the construction of the circuit breaker could not result in an internal **fault** that crosses multiple phases.
- When free standing or column-type current transformers are provided on only one side of a live tank circuit breaker protecting a transmission **element**, testing of a phase to ground **fault** between the breaker and the CTs is considered sufficient on the basis of acceptable risk.

Additionally, the design and extreme **contingency** testing does not include an internal **fault** on a circuit breaker followed by the failure of a circuit breaker to operate. Extending this approach, a

fault on the short section between the CTs and circuit breaker followed by the failure of another circuit breaker to operate need not be evaluated under testing performed in Tables 1-3.

Technical Rationale 2 – Evaluating Different Initiating Events for Single Element Contingencies

Table 1 and Table 3 include the evaluation of a three-phase **fault** on a single **element** followed by normal clearing. Typically, a three-phase **fault** followed by the loss of an **element** provides a more severe response than a different **fault** type (phase to ground, phase-to-phase and phase-phase-ground) or the loss of an **element** without a **fault**. However, there are certain instances where this assumption may not be true:

1. A phase to ground **fault** or phase-phase-ground **fault** may have a longer clearing time because of differences in **relays** that pick up ground **faults** versus phase **faults**
2. Inverter-based **resources** may perform differently for unbalanced **faults** when compared to balanced **faults**.

Typically, dynamic stability analysis that is performed for Directory #1 **contingencies** is performed in positive sequence domain, where the different behavior of inverter-based **resources** for unbalanced **faults** may not be observable.

As such, an **Area** may forego testing the loss of an **element** without a **fault** and additional unbalanced **faults** under event #1 of Tables 1 and 3, if the analysis performed by an **Area** for Directory #1 **contingencies** is restricted to positive sequence analysis, and

- if the clearing time for a three-phase **fault** on the **element** with normal clearing is the same or equivalent to the clearing time for a phase to ground, phase-to-phase and phase-phase-ground with normal clearing
- if the opening of an **element** triggers a **RAS** and the absence of a **fault** does not delay the **RAS** actuation.