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December 19, 2012

BY FEDERAL EXPRESS

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Blvd.
Warwick, RI 02888

Re: Issuance of Advisory Opinion to the Energy Facility Siting Board Regarding Narragansett Electric Co. d/b/a National Grid's Application to Construct and Alter Transmission Lines and Facilities (Interstate Reliability Project) – Docket No. 4360

Dear Ms. Massaro:

Enclosed for filing in the above-captioned matter please find on behalf of ISO New England ("ISO"), the Joint Direct Testimony of Stephen Rourke and Brent Oberlin. We are providing electronic copies to the Service List and will provide hard copies to anyone requesting one.

Please call me if there are any questions.

Sincerely,

Erica P. Bigelow

Enclosure

cc: Cynthia G. Wilson-Frias, Esq., (via Federal Express)
Alan Nault (via Federal Express)
Kevin Flynn, Esq. (via e-mail)
Service List (Dkt. 4360)

Docket No. 4360 - Narragansett Electric Co. d/b/a National Grid – Advisory Opinion to EFSB regarding need and cost-justification for proposed RI Interstate Reliability Project Service List as of 10/12/12

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STATE OF RHODE ISLAND AND
PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION **DOCKET No. 4360**

In re: Issuance of Advisory Opinion to the Energy Facility Siting Board Regarding Narragansett Electric Company d/b/a National Grid's Application to Construct and Alter Major Energy Facilities (Interstate Reliability Project)

DIRECT TESTIMONY OF STEPHEN ROURKE AND BRENT OBERLIN ON BEHALF OF ISO NEW ENGLAND INC.

Mr. Rourke is Vice President of System Planning at ISO New England Inc. and Mr. Oberlin is Director of Transmission Planning at ISO New England. Their testimony describes the responsibilities of ISO New England Inc., including its function as the regional transmission planner for the New England bulk power grid, discusses electric system reliability concerns in Rhode Island, and supports the Rhode Island portion of the Interstate Reliability Project as a solution to such reliability concerns.

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1. <u>Introduction</u>

Q1. **PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.**

A1. *Mr. Rourke.* My name is Stephen Rourke. I am Vice President of System Planning at ISO New England Inc. ("ISO"). My business address is One Sullivan Road, Holyoke, Massachusetts 01040.

Mr. Oberlin. My name is Brent Oberlin. I am Director of Transmission Planning at the ISO.

Q2. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A2. *Mr. Rourke.* I have a Bachelor of Science degree in Electrical Engineering from Worcester Polytechnic Institute and a Master of Business Administration degree from Western New England University. In my current position as Vice President of

System Planning, I am responsible for overseeing development of the annual Regional System Plan ("RSP"); analysis and approval of new transmission and generation interconnection projects, including the approval of qualification of generating capacity resources, demand resources, and import capacity resources to participate in the Forward Capacity Auction ("FCA"); implementing the Federal Energy Regulatory Commission ("FERC") approved generator interconnection process; developing the ISO's findings for Transmission Cost Allocation; and supporting the capacity markets in New England. Previously, I served as the ISO's Director, Reliability and Operations Services. I was also a former manager of the Rhode Island-Eastern Massachusetts-Vermont Energy Control center in Westborough, Massachusetts and former manager of marketing operations for Northeast Utilities/Select Energy Inc. in Berlin, Connecticut. I have over 30 years of experience in operations and planning of the New England bulk power system.

Mr. Oberlin. I began my career with the Northeast Nuclear Energy Company, a subsidiary of Northeast Utilities, in 1992 where I advanced to Project Engineer. From 1996 to 2006, I worked in the Transmission Planning Department at Northeast Utilities where I advanced to Project Manager. As Project Manager, my key responsibilities included system analysis, planning and interconnection studies for Southwest Connecticut.

I joined the ISO in 2006. Initially, I served as Manager, Area Transmission Planning for northern New England. In 2011, I was promoted to Director, Transmission Planning. My responsibilities include regional bulk power system planning, interconnection studies, evaluation of the continuing need for generators, and technical support for the Forward Capacity Market.

I am a Licensed Professional Engineer in the State of Connecticut and hold a Bachelor of Science degree in Electric Power Engineering from Rensselaer Polytechnic Institute.

Q3. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE RHODE ISLAND PUBLIC UTILITIES COMMISSION?

A3. *Mr. Rourke.* No, I have not.

Mr. Oberlin. No, I have not.

2. <u>Summary of Testimony</u>

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A4. Under the regional planning process, Transmission Owners in New England are responsible for obtaining siting approvals necessary to construct transmission upgrades identified to meet reliability needs.[1] If requested by the Transmission Owner, the ISO will undertake reasonable efforts in the siting proceeding to assist in supporting the reliability need for the transmission upgrade. As such, the ISO is submitting this testimony to support the need for the IRP based on reliability criteria established by the North American Electric Reliability Corporation ("NERC"), the Northeast Power Coordinating Council, Inc. ("NPCC") and the ISO.

Q5. PLEASE SUMMARIZE YOUR TESTIMONY.

A5. Based on studies to date and applicable reliability standards, the ISO is concerned about the reliability of the existing electricity delivery system in southern New England and the transfer of power over the transmission system connecting Massachusetts, Connecticut, and Rhode Island. In an effort to evaluate the ability of the transmission system in southern New England to continue to perform

[1] See Schedule 3.09 (a) 1.2 of the Transmission Operating Agreement by and among the Participating Transmission Owners and the ISO located at: http://www.iso-ne.com/regulatory/toa/index.html

reliably, a working group consisting of system planning engineers from the ISO, National Grid and Northeast Utilities was formed (the "Working Group"). The Working Group undertook a comprehensive forward-looking transmission planning study, known as the Southern New England Transmission Reliability analysis. This analysis was documented in the “New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment,” dated April 2011 (“April 2011 Needs Assessment”) and filed by National Grid in the Siting Board docket on July 19, 2012. This analysis was updated by ISO New England in 2012 with the newest information available at the time of the study and is documented in the “Follow-Up Analysis to the 2011 New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Analysis,” dated September 2012 (“September 2012 Needs Assessment”) and filed by National Grid in this proceeding on November 20, 2012.

The September 2012 Needs Assessment evaluated the reliability of the southern New England Transmission system under 2022 projected system conditions (*i.e.*, the 10-year planning horizon). The September 2012 Needs Assessment also accounted for the results from FCA 6, which was held in April 2012; the most recent load forecast as reported in the 2012 Capacity, Energy, Loads and Transmission ("CELT") report; and the newly formulated Energy Efficiency forecast published in the CELT report.

Transmission reliability, which can be described as the ability to supply the area's load under certain resource outages and all criteria contingency events, all within the applicable equipment ratings, is a major concern for the southern New England system. Critical weaknesses in Rhode Island are identified in Section 5 of the September 2012 Needs Assessment, which describes various reliability criteria violations. Without transmission improvements, the system may fail to provide reliable service in these areas.

After establishing the existence, nature and location of the reliability concerns, the Working Group identified a number of possible solutions and tested each to determine its ability to eliminate the criteria violations. As a result, a number of possible transmission solutions were developed. This analysis is detailed in the "New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Solution Study Report," dated February 2012 ("February 2012 Solutions Report"). The ISO has updated the February 2012 Solutions Study in a report entitled "Follow-up Analysis to the 2012 New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Solution Study Report," dated September 2012, the ("September 2012 Solutions Study"). The September 2012 Solutions Study was also filed by National Grid in this proceeding on November 20, 2012. The September 2012 Solutions Study explains that the IRP continued as the preferred transmission solution to meet the reliability need identified in the September 2012 Needs Assessment.

The IRP consists of approximately 75 miles of new 345 kV transmission lines to be developed predominantly along existing rights-of-way, as well as modifications to existing substations and switching stations. In Rhode Island, the project consists of two new 345 kV transmission lines; relocation, reconstruction and, in some cases, reconductoring of existing 345 kV and 115 kV transmission lines; and reconstruction of an existing switching station (the "Project"). All such work is to be done in the municipalities of Burrillville and North Smithfield. A more specific description is found in National Grid's Application and the pre-filed testimony of Mr. Beron.

3. <u>ISO's Mission and Responsibilities</u>

Q6. WHY WAS THE ISO ESTABLISHED?

A6. The "Independent System Operator" concept was developed by FERC as part of the framework to support competitive electricity markets. In 1996, FERC stated its principles for the ISO operation and governance in FERC Order 888.[2] FERC identified Independent System Operator principles as: providing independent, open and fair access to the region's transmission system; establishing a non-discriminatory governance structure; facilitating market based wholesale electricity rates; and ensuring the efficient management and reliable operation of the regional power system.

The ISO was established to be the Independent System Operator of the New England power grid on July 1, 1997[3] and it assumed certain operating and transmission reservation responsibilities which had previously been carried out by

[2] Promoting Wholesale Competition Through Open Access, Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 75 FERC ¶ 31,036 (1996)(establishing principles for ISO's operation and governance).

[3] New England Power Pool, Order Conditionally Authorizing Establishment of an Independent System Operator and Disposition of Control Over Jurisdictional Facilities, 79 FERC ¶ 61,374 (1997) (authorizing formation of ISO).

the New England Power Pool ("NEPOOL"), which transferred staff and assets to the ISO. In May 1999, the ISO commenced administration of the restructured wholesale electricity marketplace for the region.[4] In June 2001, FERC conferred authority on the ISO to be responsible for the regional transmission planning process.[5] In March 2004, FERC granted the ISO status as a Regional Transmission Organization ("RTO"),[6] and the ISO began operation as an RTO in February 2005.

Q7. DOES THE ISO MAKE ANY PROFIT FROM ITS ROLE AS THE INDEPENDENT SYSTEM OPERATOR?

A7. No. As the Independent System Operator, the ISO complies with FERC Order No. 889.[7] In this regard, the ISO is an independent, private, non-profit, non-stock, company. The ISO therefore has no shareholders, and its Board of Directors and employees are barred from being employed by or owning shares in Market Participants. Its budget is reviewed and approved annually by FERC, and the ISO only recoups its annual expenses.

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[4] New England Power Pool, Order Conditionally Accepting New and Revised Market Rules, 87 FERC ¶ 61,045 (1999) (authorizing ISO-NE to administer the restructured wholesale electricity marketplace).

[5] ISO New England Inc. & New England Power Pool, Order On Rehearing Requests and Compliance Filings, 95 FERC ¶ 61384 (2001) (authorizing ISO to oversee regional transmission planning).

[6] Order Granting RTO Status Subject to Fulfillment of Requirements and Establishing Hearing and Settlement Judge Procedures 106 FERC ¶ 61,280 (2004)(granting ISO-New England RTO status).

[7] Open Access Same-Time Information System Conduct, Order No. 889, 75 FERC ¶ 61,078 (1996) (rules establishing and governing Open Access Same-Time Information System).

Q8. WHAT ARE THE ISO'S MISSION AND RESPONSIBILITIES?

A8. The ISO manages the New England region's electric power system, operates the wholesale electricity market, administers the region's Open Access Transmission Tariff ("OATT"), and conducts regional transmission planning. More specifically, the ISO's responsibilities include independently operating and maintaining a highly reliable transmission system, promoting efficient wholesale electricity markets, and working collaboratively and proactively with state and federal regulators, NEPOOL Participants, and other stakeholders in pursuit of these goals.

As pertinent to this proceeding, FERC has conferred upon the ISO responsibility for conducting long-term system planning for New England.[8] As such, the ISO must maintain a level of system reliability that meets criteria established by NERC, NPCC, and the ISO's own planning standards. Applicable reliability standards and criteria are discussed more fully below.

It is appropriate to add that the massive outage that struck the North American electric power system on August 14, 2003, has underscored the significance of the ISO's mission and responsibilities. The event demonstrated the need for appropriate reliability standards, effective monitoring of compliance, and, most importantly, a reliable power transmission system. A well coordinated regional

[8] ISO New England Inc. and New England Power Pool, Order on Reh'g, 95 FERC ¶ 61,384 (2001) (authorizing ISO to oversee regional transmission planning); ISO New England Inc and New England Power Pool¸ 103 FERC ¶ 61,304 (2003) (finding that "[w]e are persuaded by ISO-NE's arguments it is the appropriate authority to approve planning for transmission upgrades…"); Order Accepting Compliance Filing, As Modified, 123 FERC ¶ 61,113 (2008) (accepting ISO Tariff provisions regarding transmission planning).

system plan and additional power system infrastructure are more essential than ever to ensure reliability of service to load, because without a well-planned system, there may not be operating options available to maintain reliable service.

Q9. WHAT IS THE ISO'S ROLE IN CONDUCTING REGIONAL TRANSMISSION PLANNING?

A9. The ISO is responsible for conducting long-term regional transmission planning for the New England region. Attachment K to the ISO's OATT sets forth the ISO's responsibility for regional transmission planning in New England. Specifically, Attachment K requires the ISO to undertake an assessment of the needs of the bulk power system. The ISO annually prepares a comprehensive RSP for the six New England states that includes forecasts of future load and how the electrical transmission system as planned can meet the growing demand by adding generating resources, energy efficiency or other demand-side resources, and transmission.

Transmission upgrades are planned and required, as needed, throughout New England to maintain system reliability, improve the efficiency of system operations, insure adequate system transfer capability to serve major load pockets, and reduce locational dependence on generating units. The RSP identifies additional work required to fully develop a highly coordinated regional plan to meet the reliability requirements of New England. The regional transmission plan is developed through an open process and through participation of, and review by, interested parties, including state regulators and NEPOOL market participants.

To ensure that the ISO receives the full benefit of input from all interested stakeholders, the ISO convenes multiple planning meetings over the course of the year with the Planning Advisory Committee ("PAC")—a stakeholder group that is open to any interested entity, including, but not limited to, Transmission Customers, Market Participants, and various officials of the New England states. The ISO also coordinates the regional system planning process with the Participating Transmission Owners and other asset owners in New England.

4. <u>Reliability Standards</u>

Q10. WHAT CRITERIA DOES THE ISO USE IN DETERMINING WHETHER ELECTRICITY SERVICE IN NEW ENGLAND IS RELIABLE?

A10. As explained below, there are numerous criteria employed in planning a reliable transmission system. Overall, these criteria all seek to satisfy one overarching objective - to ensure an electric system that can reliably deliver electric energy across the transmission network.

The ISO plans the New England regional transmission system to comply with the reliability and criteria standards established by NERC, NPCC and the ISO. The ISO's implementation and compliance with NERC/NPCC Reliability Rules are codified in its Operations, Planning, and Administrative manuals and other written procedures. NERC oversees a number of regional councils, one of which is the NPCC. The NPCC covers New York, New England, and parts of Canada. Under this framework, NERC has established a general set of mandatory standards applicable to all geographic areas. NPCC has established a set of criteria particular to the Northeast, although they also encompass the more general NERC standards. In turn, the ISO has developed criteria specific to New England that coordinate with the NPCC criteria. Similar standards and criteria exist throughout the nation and other portions of North America.

Whether developed by NERC, NPCC, or the ISO, the standards and criteria applicable to the New England transmission system are applied in a deterministic fashion (*i.e.*, for specific disturbances or "contingencies") in order to assess the ability of the transmission system to perform under a series of defined contingency situations. Specifically, these standards and criteria dictate a set of operating circumstances or contingencies under which the New England transmission system must perform without experiencing overloads, instability, or voltage violations. For NPCC, these performance measurements are set forth in NPCC Reliability Reference Directory # 1, "Design and Operation of the Bulk Power System," which is included with this testimony as Attachment A. The ISO's planning standards are defined in Planning Procedure No. 3, "Reliability Standards for the New England Bulk Power Supply System" ("PP3"), which is included with this testimony as Attachment B. PP3 provides consistent system planning criteria throughout New England. Analyses of these contingencies also include assessment of the potential for widespread cascading outages due to overloads, instability or voltage collapse.

5. The Reliability of the Transmission System in Southern New England

Q11. DOES THE ISO HAVE CONCERNS REGARDING THE ABILITY OF THE TRANSMISSION SYSTEM IN SOUTHERN NEW ENGLAND GENERALLY AND RHODE ISLAND SPECIFICALLY TO PROVIDE CONTINUED RELIABLE ELECTRIC SERVICE?

A11. Yes. The September 2012 Needs Assessment identifies and details reliability concerns with the southern New England system. As that report shows, there is an increasingly high risk that the system will be unable to withstand single and multiple element contingencies following the single loss or outage of certain critical facilities in these areas as the system approaches or exceeds forecasted peak load levels. Single element contingencies refer to the loss of an individual transmission line, transformer, or generator due to any event, such as a lightning strike. Multiple element contingencies refer to a single event which removes multiple pieces of generating or transmission equipment from service, such as may occur following the failure of a circuit breaker or the simultaneous loss of multiple transmission circuits which are on the same tower. These contingencies can result in thermal and voltage violations of the reliability standards and criteria established by NERC, the NPCC and the ISO. As shown in Section 5 of the September 2012 Needs Assessment (Sections 5.2.3.1, 5.2.3.2, and 5.2.3.3), there are thermal violations in Rhode Island under N-1-1 testing (Tables 5-2, 5-4, and 5-5). Additionally, Section 5.2.3.3 shows the potential for a voltage collapse of the Rhode Island transmission system.

Q12: WHAT SPECIFICALLY ARE THE ISO'S RELIABILITY CONCERNS IN THE SOUTHERN NEW ENGLAND AREA?

A12. The ISO is concerned with thermal overloading of transmission lines and poor voltage performance under numerous contingencies. As explained in the September 2012 Needs Assessment, for purposes of the study, New England was divided into three sub-areas: eastern New England, western New England, and Rhode Island. Due to the nature of the system, for the eastern New England study, Greater Rhode Island was considered part of the western New England sub-area. For the western New England study, Greater Rhode Island was considered part of the eastern New England sub-area.

For the eastern New England Reliability Analysis, N-1 and N-1-1 thermal violations occur on numerous transmission lines, which indicate a need to increase the eastern New England import transfer capability.

For the western New England Reliability Analysis, certain 345 kV lines that form the central 345 kV East-West path connecting eastern Massachusetts to western Massachusetts were thermally overloaded as the other remaining 345 kV lines were lost under a N-1-1 contingency event.

The ISO presented the update to these system deficiencies at the July 18, 2012 PAC meeting[9] based on the latest load, resource and system data.

[9] http://www.isone.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/jul182012/news_2012_needs_solutions.pdf

Q13. HOW DO THERMAL OVERLOADS OCCUR?

A13. Thermal overloads occur when transmission facilities, often as a result of a contingency event elsewhere in the system, carry current in excess of their design capacity. As an example, overloaded lines build up heat beyond their temperature limits and may sag in an unsafe manner or fail, redirecting power to other lines, which in turn may become overloaded; a pattern that may result in a sustained loss of load, equipment damage and cascading outages.

Transmission lines have normal and emergency current ratings. Normal ratings are the rating limits within which a line should generally operate below at all times. Normal line loading ratings are violated when a transmission line is used to carry current in excess of its rating for sustained planned system configurations. Transmission lines can be operated at current loads that exceed the normal rating, but only for a limited period of time, such as following a sudden equipment outage. An emergency current rating is the upper operational limit of the line. Consequences of operating lines between normal and emergency limits include reduced life expectancy of the transmission line and a reduction in the ability to respond to subsequent outages. Exceeding the emergency ratings of transmission lines can result in line mechanical failure or sagging into public areas, such as highways; thereby compromising public safety and causing uncontrolled outages (*i.e.*, blackouts). Lines that sagged into trees in Ohio contributed to the Northeast Blackout of August 2003.

Q14. WHY IS LOW VOLTAGE A CONCERN?

A14. Low voltage at the consumer level is a concern because it can damage equipment and interfere with the proper operation of appliances and machinery. At the transmission level, insufficient voltage can also cause unanticipated and undesirable protective equipment operation, voltage collapse and loss of load. This is a significant concern for the Rhode Island transmission system under certain N-1-1 conditions.

Q15. WHAT CONSEQUENCES CAN AN UNCONTROLLED BLACKOUT HAVE?

A15. There are two consequences of an uncontrolled blackout. First, it is often difficult to accurately predict how large an area will be affected by blackout, and as a result, it could encompass the entire northeastern United States, as happened on November 9, 1965 and again on August 14, 2003, when parts of the Midwest and Canada were also affected along with the Northeast. Second, it may result in equipment damage that will hamper restoration of service, thus prolonging outages, and make efforts to remedy the system outage more difficult.

Q16. IS THE NEW ENGLAND SYSTEM REQUIRED TO COMPLY WITH ALL NERC, NPCC AND ISO STANDARDS AND CRITERIA?

A16. Yes.

6. Benefits of the Project

Q17. WHAT RELIABILITY BENEFITS WILL THE PROJECT PROVIDE TO THE TRANSMISSION SYSTEM?

A17. The installation of the Interstate Reliability Project will address the reliability issues described above by eliminating the thermal and voltage criteria violations and improving transfer capabilities between eastern New England and western New England. Moreover, the transmission upgrades will serve to ensure that the transmission system remains in compliance with reliability standards and criteria established by NERC, the NPCC, and the ISO. The Project, including the Rhode Island portion described above in A5, provides two new 345 kV lines into West Farnum which resolves potential voltage collapse concerns in Rhode Island. While it is extremely difficult to predict the extent of the impact of a voltage collapse, this event could potentially lead to a blackout in almost all of Rhode Island and parts of Massachusetts. The 345 kV line into Millbury substation via West Farnum provides a new import line into eastern New England and allows for the movement of power from western New England and Greater Rhode Island to reliably serve load in eastern New England during capacity deficiency conditions in eastern New England. The 345 kV line into Card Street substation via Lake Road and West Farnum provides a new import path into Connecticut and western New England and allows for the movement of power from eastern New England and Greater Rhode Island to reliably serve load in Connecticut and western New England during capacity deficiency conditions in the west. The project resolves the identified 115 kV thermal violations on the Rhode Island transmission system while moving power into eastern New England and western New England since more power is transferred on the 345 kV network rather than the 115 kV lines in Rhode Island, Connecticut, and Massachusetts.

Q18. WHY IS TRANSFER CAPABILITY A RELIABILITY CONCERN?

A18. When there are limited resources or resources are unavailable in a local area, the transmission system needs to be capable of delivering power from other areas in the system to continue to serve the load. Without sufficient transmission system capacity, the needed power transfer will overload the existing transmission system.

Q19. WAS THERE A PRE-DETERMINED TRANSFER LEVEL IN SETTING UP THE MODELS IN THE SEPTEMBER 2012 NEEDS ASSESSMENT?

A19. No.

Q20. THEN PLEASE EXPLAIN HOW THE TRANSFERS WERE ESTABLISHED.

A20. At a high level, the process starts by establishing the load in the area being studied. In the case of the proposed line between Millbury and West Farnum, the transfers to eastern New England are driven by the load in eastern New England. Once the load is established, the resources are considered. These resources include generation, demand resources, and future energy efficiency programs. Most demand resources and energy efficiency programs reduce the amount of load which must be served. With the load and resources established, forced outages of resources are modeled, prior to applying contingencies. These conditions establish the amount of power that needs to be transferred into the area to serve the load in the base case. In other words, the transfers into the area are simply the load and losses in the area, minus the resources assumed to be available. When there are insufficient resources to serve load in the area, additional power must be imported.

Q21. DID THE ISO CONSIDER MARKET RESPONSES IN EVALUATING THE NEED FOR THE PROJECT?

A21. Yes. The ISO's Tariff requires that the ISO "reflect proposed market responses in the regional system planning process."[10] Market responses include, but are not limited to, demand-side projects, generation, distributed generation and Merchant Transmission Facilities. The ISO evaluates the need for Regulated Transmission Upgrades based on viable market responses that have been proposed and (i) have cleared in a FCA, (ii) are contractually bound by a state-sponsored Request for Proposals ("RFP") or (iii) have a financially binding obligation pursuant to a contract.[11] As explained in the September 2012 Needs Assessment, the ISO considered the impact on the need for the IRP based on the cleared resources in the most recent FCA, the most recent load forecasts and forecasted state-sponsored Energy Efficiency measures through 2022. Even considering these updates, there continues to be a need for the IRP within the 10-year planning horizon.

[10] Section 4.2(a) of Attachment K to the Tariff
[11] *Id.*

Q22. WERE THESE FINDINGS PRESENTED TO THE PAC?

A22. Yes. The findings supporting the determination that the IRP continues to be needed within the 10-year planning horizon were presented at the July 18, 2012 PAC meeting.

Q23. DOES THE ISO SUPPORT THE IRP?

A23. Yes. As described above and in the September 2012 Needs Assessment, the ISO is concerned about the ability of the existing transmission system to maintain reliable electric service in southern New England. The IRP is the preferred transmission solution to meet the reliability needs identified in the September 2012 Solutions Study.

Q24. DOES THIS CONCLUDE YOUR TESTIMONY?

A24. Yes, thank you.

ISO ATTACHMENT LIST –

Attachment A	NPCC Reliability Reference Directory # 1 "Design and Operation of the Bulk Power System."
Attachment B	ISO Planning Procedure No. 3, "Reliability Standards for the New England Bulk Power Supply System."

Attachment A

NPCC Reliability Reference Directory # 1 “Design and Operation of the Bulk Power System”

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

NPCC
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

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			New
1	4/20/2012	Errata changes in Appendix B and Appendix E.	Errata

Attachment A

Table of Contents

Attachment A

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 these criteria is to provide a "design-based approach" to ensure the **bulk power system** is designed and operated to a level of reliability such that the loss of a major portion of the system, or unintentional separation of a major portion of the system, will not result from any design **contingencies** referenced in Sections 5.4.1 and 5.4.2. In NPCC the technique for assuring the reliability of the **bulk power system** is to require that it be designed and operated to withstand representative **contingencies** as specified in this Directory. Analyses of simulations of these **contingencies** include assessment of the potential for widespread cascading outages due to overloads, instability or voltage collapse. 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**.

Criteria described in this document are to be used in the design and operation of the **bulk power system.** These criteria are applicable to all entities which are part of or make use of the **bulk power system**.

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 and include:

a. Consideration of a balanced relationship among the fuel type, capacity, physical characteristics (peaking/base **load**/etc.), and location of **resources**.

b. Consideration of a balanced relationship among transmission system **elements** to avoid excessive dependence on any one transmission circuit, structure, right-of-way, or substation.

c. Transmission systems should provide flexibility in switching arrangements, voltage control, and other control measures

1.4 Effective Date **-** December 01, 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.

1.6 Applicability

1.6.1 Functional Entities

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

2.0 Terms Defined in this Directory

Terms appearing in bold typeface in this Directory (including the Appendices) are defined in Appendix A.

3.0 NERC ERO Reliability Standard Requirements

The NERC ERO Reliability Standards containing requirements that are associated with this Directory include, but may not be limited to:

3.1 EOP-001-0 - Emergency Operations Planning
3.2 FAC-011-2 - System Operating Limits Methodology for the Operations Horizon
3.3 IRO-002-1 - Reliability Coordination - Facilities
3.4 IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
3.5 MOD-010-0 - Steady-State Data for Transmission System Modeling and Simulation
3.6 MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures
3.7 MOD-012-0 — Dynamics Data for Transmission System Modeling and Simulation
3.8 MOD-013-1 — RRO Dynamics Data Requirements and Reporting Procedures
3.9 MOD-014-0 — Development of Interconnection-Specific Steady State System Models
3.10 MOD-015-0 — Development of Interconnection-Specific Dynamics System Models
3.11 MOD-016-1 — Actual and Forecast Demands, Net Energy for Load,

Controllable DSM
3.12 TOP-001-1 — Reliability Responsibilities and Authorities
3.13 TOP-002-2 — Normal Operations Planning
3.14 TOP-003-0 — Planned Outage Coordination
3.15 TOP-004-2 — Transmission Operations
3.16 TPL-001-0 — System Performance Under Normal Conditions
3.17 TPL-002-0 — System Performance Following Loss of a Single BES Element NPCC Regional Reliability Standard Requirements
3.18 TPL-003-0 — System Performance Following Loss of Two or More BES Elements
3.19 TPL-004-0 — System Performance Following Extreme BES Events
3.20 TPL-005-0 — Regional and Interregional Self-Assessment Reliability Reports
3.21 TPL-006-0 — Assessment Data from Regional Reliability Organizations
3.22 VAR-001-1 — Voltage and Reactive Control

4.0 NPCC regional Reliability Standards Requirements

None

5.0 NPCC Full Member, More Stringent Criteria

NPCC provides a forum for coordinating the design and operations of its five Reliability Coordinator Areas. NPCC shall conduct regional and interregional studies, and assess and monitor Planning Coordinator Area studies and Reliability Coordinator operations to assure conformance to these criteria through committees, task forces, and working groups.

It is the responsibility of each Reliability Coordinator to ascertain that their portion of the **bulk power system** is operated in conformance with these criteria. It is the responsibility of each Transmission Planner and Planning Coordinator to ascertain that their portion of the **bulk power system** is designed in conformance with these criteria

5.1 General Requirements

Specific system conditions may require Planning Coordinators or Reliability Coordinators to develop criteria which are more stringent than those set out herein. Any constraints imposed by these more stringent criteria will be observed. It is also recognized that these Criteria are not necessarily applicable to those **elements** that are not a part of the **bulk power system** or in the portions of a system where instability or overloads will not jeopardize the reliability of the remaining **bulk power system.**

5.1.1 Design Criteria

These design criteria will be used in the assessment of the **bulk power system** by each of the NPCC Transmission Planners and Planning Coordinators, and in the reliability testing at the Transmission Operator, Reliability Coordinator and Regional Council levels.

Design studies shall assume **power** flow conditions utilizing transfers, **load** and generation conditions which stress the system. Transfer capability studies shall be based on the **load** and generation conditions expected to exist for the period under study. All **reclosing** facilities shall be assumed in service unless it is known that such facilities will be rendered inoperative.

S**pecial protection systems (SPS)** shall be used judiciously and when employed shall be installed, consistent with good system design and operating criteria found in Directory #7 – *Special Protection Systems*.

A SPS may be used to provide protection for infrequent **contingencies**, or for temporary conditions that may exist such as project delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages. A **SPS** may also be applied to preserve system integrity in the event of severe facility outages and extreme **contingencies.** The decision to employ a **SPS** shall take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits.

The requirements of **special protection systems** are defined in the NPCC *Bulk Power System Protection Criteria*, (Directory#4), and the *Special Protection Systems*, (Directory #7).

5.1.2 Operating Criteria

Coordination among and within the Reliability Coordinator Areas of NPCC is essential to the reliability of interconnected operations. Timely information concerning system conditions shall be transmitted by the NPCC Reliability Coordinators to other NPCC Reliability Coordinators, adjacent Reliability Coordinators or other entities as needed to assure reliable operation of the **bulk power system**.

The operating criteria represent the application of the design criteria to inter-Reliability Coordinator Area, intra- Reliability Coordinator Area operation.

The operating criteria define the minimum level of reliability that shall apply to inter-Reliability Coordinator Area operation. Where inter-Reliability Coordinator Area reliability is affected, each Reliability

Coordinator shall establish limits and operate so that the **contingencies** stated in Section 5.5.1 and 5.5.2 can be withstood without causing a **significant adverse impact** on other Reliability Coordinator Areas.

When adequate **bulk power system** facilities are not available, **special protection systems** (SPS) may be employed to maintain system security.

Two categories of transmission transfer capabilities, normal and **emergency**, are applicable. Normal transfer capabilities are to be observed unless an **emergency** is declared.

5.1.3 Data Exchange Requirements for Modeling and System Analysis

It is the responsibility of NPCC and NPCC Members to protect the proprietary nature of the following information and to ensure it is used only for purposes of efficient and reliable system design and operation. Also, any sharing of such information must not violate anti-trust laws.

For reliability purposes, Reliability Coordinators 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. Each Registered Entity within an NPCC Reliability Coordinator Area shall provide needed information to its Reliability Coordinator as required. Analysis and modeling of the interconnected power system is required for reliable design and operation. Data needed to analyze and model the electric system and its component facilities must be developed, maintained, and made available for use in interconnected operating and planning studies, including data for fault level analysis.

Reliability Coordinators and Registered Entities shall maintain and submit, as needed, data in accordance with applicable NPCC Procedures.

Data submitted for analysis representing physical or control characteristics of equipment shall be verified through appropriate methods. System analysis and modeling data must be reviewed annually, and verified on a periodic basis. Generation equipment, and its component controllers, shall be tested to verify data.

5.2 Resource Adequacy – Design Criteria

The probability (or risk) of disconnecting **firm load** due to resource deficiencies shall be, on average, not more than one day in ten years as determined by studies conducted for each Resource Planning and Planning Coordinator Area. Compliance with this criterion shall be evaluated probabilistically, such that the loss of **load** expectation (LOLE) of disconnecting **firm load** due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or **load** relief from available operating procedures.

5.3 Resource Adequacy – Operating Criteria

Each Balancing Authority shall have procedures in place to schedule outages and deratings of **resources** in such a manner that the available **resources** will be adequate to meet the Resource Planner's and Planning Coordinator's forecasted demand and **reserve** requirements, in accordance with the NPCC *Operating Reserve Criteria* (Directory#5).

For consistent evaluation and reporting of **resource** adequacy, it is necessary to measure the net capability of generating units and **loads** utilized as a **resource** of each Planning Coordinator Area.

5.4 Transmission Design Criteria

The portion of the **bulk power system** in each Planning Coordinator Area and in each Transmission Planning Area shall be designed with sufficient transmission capability to serve forecasted demand under the conditions noted in Sections 5.4.1 and 5.4.2. These criteria will also apply after any critical generator, transmission circuit, transformer, series or shunt compensating device or HVdc pole has already been lost, assuming that the Planning Coordinator Area generation and **power** flows are adjusted between outages by the use of **ten-minute reserve** and where available, phase angle regulator control and HVdc control.

Anticipated transfers of **power** from one Planning Coordinator Area to another, as well as within Planning Coordinator Areas, shall be considered in the design of transmission facilities. Transmission transfer capabilities shall be determined in accordance with the conditions noted in Sections 5.4.1 and 5.4.2.

5.4.1 Stability Assessment

Stability of the **bulk power system** shall be maintained during and following the most severe of the **contingencies** stated below, with due regard to **reclosing**. For each of the **contingencies** below that involve a fault, **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**.

a. A permanent three-phase fault on any generator, transmission circuit, transformer or bus section with **normal fault clearing**.

b. Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with **normal fault clearing**. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded. Other similar situations can be excluded on the basis of acceptable risk, provided that the Reliability Coordinating Committee specifically accepts each request for exclusion.

c. A permanent phase to ground fault on any transmission circuit, transformer, or bus section with **delayed fault clearing**.

d. Loss of any **element** without a fault.

e. A permanent phase to ground fault on a circuit breaker with **normal fault clearing**. (**Normal fault clearing** time for this condition may not always be high speed.)

f. Simultaneous permanent loss of both poles of a direct current bipolar facility without an ac fault

g. The failure of a circuit breaker to operate when initiated by a **SPS** following: loss of any **element** without a fault; or a permanent phase to ground fault, with **normal fault clearing**, on any transmission circuit, transformer or bus section.

5.4.2 Steady State Assessment

a. Each Transmission Planner shall design its system in accordance with these criteria and its own voltage control procedures and criteria, and coordinate these with adjacent Transmission Planner Areas**.** Adequate **reactive power** resources and appropriate controls shall be installed in each Transmission Planner Area to maintain voltages within normal limits for pre-**disturbance** conditions, and within **applicable emergency limits** for the system conditions that exist following the **contingencies** specified in 5.4.1.

b. Line and equipment loadings shall be within normal limits for pre-**disturbance** conditions and within **applicable emergency limits** for the system conditions that exist following the **contingencies** specified in 5.4.1.

5.4.3 Fault Current Assessment

Each Transmission Planner and Planning Coordinator shall establish 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 potential operating conditions, and coordinate these procedures with adjacent Planning Coordinator Areas.

5.5 Transmission Operating Criteria

Scheduled outages of facilities that affect inter-Reliability Coordinator Area reliability shall be coordinated sufficiently in advance of the outage to permit the affected Reliability Coordinators to maintain reliability. Each Reliability Coordinator shall notify adjacent Reliability Coordinators of scheduled or forced outages of any facility on the NPCC Transmission Facilities Notification List and of any other condition which may impact on inter-Reliability Coordinator Area reliability. Work on facilities which impact inter-Reliability Coordinator Area reliability shall be expedited to minimize the time that the facilities are out of service.

Individual Reliability Coordinator Areas shall be operated in a manner such that the **contingencies** noted in Section 5.5.1 and 5.5.2 can be withstood and do not adversely affect other Reliability Coordinator Areas.

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

5.5.1 Normal Transfers

Pre-**contingency** voltages, line and equipment loadings shall be within normal limits. Unless specific instructions describing alternate action are in effect, normal transfers shall be such that manual **reclosing** of a faulted **element** can be carried out before any manual system adjustment, without affecting the **stability** of the **bulk power system**.

Stability of the **bulk power system** shall be maintained during and following the most severe of the **contingencies** stated below, with due regard to **reclosing.** For each of the **contingencies** stated below that involves a fault, **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**.

a. A permanent three-phase fault on any generator, transmission circuit, transformer or bus section, with **normal fault clearing**.

b. Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with **normal fault clearing**. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded. Other similar situations can be excluded on the basis of acceptable risk, provided that the Reliability Coordinating Committee specifically accepts each request for exclusion.

c. A permanent phase to ground fault on any transmission circuit, transformer, or bus section with **delayed fault clearing**.

d. Loss of any **element** without a fault.

e. A permanent phase to ground fault on a circuit breaker, with **normal fault clearing**. (**Normal fault clearing** time for this condition may not always be high speed.)

f. Simultaneous permanent loss of both poles of a direct current bipolar facility without an ac fault.

g. The failure of a circuit breaker to operate when initiated by a **SPS** following: loss of any **element** without a fault; or a permanent phase to ground fault, with **normal fault clearing**, on any transmission circuit, transformer or bus section.

Reactive power resources shall be maintained in each Reliability Coordinator Area in order to maintain voltages within normal limits for pre-**disturbance** conditions, and within **applicable emergency limits** for the system conditions that exist following the **contingencies** specified in the foregoing. Adjoining Reliability Coordinators shall mutually agree upon procedures for inter-Reliability Coordinator Area voltage control.

Line and equipment loadings shall be within normal limits for pre-**disturbance** conditions and within **applicable emergency limits** for the system conditions that exist following the **contingencies** specified in the foregoing.

Since **contingencies** b, c, e, f, and g, are not confined to the loss of a single **element**, individual Transmission Operators and Reliability Coordinators may choose to permit a higher post **contingency** flow on remaining facilities than for **contingencies** a and d. This is permissible providing operating procedures are documented to accomplish corrective actions; the loadings are sustainable for at least the anticipated time required to effect such action, and other Transmission Operator Areas or Reliability Coordinator Areas will not be subjected to the higher flows without prior agreement.

5.5.2 Emergency Transfers

When **firm load** cannot be supplied within normal limits in a Transmission Operator Area, or a portion of a Transmission Operator Area, transfers may be increased to the point where pre-**contingency** voltages, line and equipment loadings are within **applicable emergency limits**. **Emergency** transfer levels may require generation adjustment before manually **reclosing** faulted **elements**.

Stability of the **bulk power system** shall be maintained during and following the most severe of the following **contingencies**, and with due regard to **reclosing**:

a. A permanent three-phase fault on any generator, transmission circuit, transformer or bus section, with **normal fault clearing**.

b. The loss of any **element** without a fault.

Immediately following the most severe of these **contingencies**, voltages, line and equipment loadings will be within **applicable emergency limits**.

5.5.3 Post Contingency Operation

Immediately after the occurrence of a **contingency**, the status of the **bulk power system** must be assessed and transfer levels must be adjusted, if necessary, to prepare for the next **contingency**. If the readjustment of generation, **load** resources, phase angle regulators, and direct current facilities is not adequate to restore the system to a secure state, then other measures such as voltage reduction and shedding of firm **load** may be required. System adjustments shall be completed as quickly as possible, but in all cases within 30 minutes after the occurrence of the **contingency**.

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 after the **contingency** occurs and other measures will maintain post **contingency** loadings within **applicable emergency limits**.

Emergency measures, including the pre-**contingency** disconnection of **firm load** if necessary, must be implemented to limit transfers to within the requirements of 5.5.2 above.

5.5.4 Operation under High Risk Conditions

Operating to the **contingencies** listed in Sections 5.5.1 and 5.5.2 is considered to provide an acceptable level of **bulk power system** security. Under certain unusual conditions, such as severe weather, the expectation of occurrence of some **contingencies**, and the associated consequences, may be judged to be temporarily, but significantly, greater than the long-term average expectation. When these conditions, referred to as high risk conditions, are judged to exist in a Transmission Operator Area, consideration should be given to operating in a more conservative manner than that required by the provisions of Sections 5.5.1 and 5.5.2.

5.6 Extreme Contingency Assessment

Extreme **contingency** assessment recognizes that the **bulk power system** can be subjected to events which exceed, in severity, the **contingencies** listed in Section 5.4.1. One of the objectives of extreme **contingency** assessment is to determine, through planning studies, the effects of extreme **contingencies** on system performance. This is done in order to obtain an indication of system strength, or to determine the extent of a widespread system **disturbance**, even though extreme **contingencies** do have low probabilities of occurrence.

The specified extreme **contingencies** listed below are intended to serve as a means of identifying some of those particular situations that could result in a widespread **bulk power system disturbance**. It is the responsibility of each Planning Coordinator Area to identify any additional extreme **contingencies** to be assessed.

Assessment of the extreme **contingencies** listed below shall examine post **contingency** steady state conditions, as well as **stability**, overload, cascading outages and vołage collapse. Pre-**contingency load** flows chosen for analysis shall reflect reasonable **power** transfer conditions within or between Planning Coordinator Areas.

Analytical studies shall be conducted to determine the effect of the following extreme **contingencies**:

a. Loss of the entire capability of a generating station.

b. Loss of all transmission circuits emanating from a generating station, switching station, dc terminal or substation

c. Loss of all transmission circuits on a common right-of-way.

d. Permanent three-phase fault on any generator, transmission circuit, transformer, or bus section, with **delayed fault clearing** and with due regard to **reclosing**.

e. The sudden dropping of a large **load** or major **load** center.

f. The effect of severe **power** swings arising from **disturbances** outside the Council's interconnected systems.

g. Failure of a **special protection system**, to operate when required following the normal **contingencies** listed in Section 5.4.1.

h. The operation or partial operation of a **special protection system** for an event or condition for which it was not intended to operate.

i. Sudden loss of fuel delivery system to multiple plants, (i.e. gas pipeline **contingencies**, including both gas transmission lines and gas mains.)

Note: The requirement of this section is to perform extreme **contingency** assessments. In the case where extreme **contingency** assessment concludes there are serious consequences, an evaluation of implementing a change to design or operating practices to address such **contingencies** shall be conducted.

5.7 Extreme System Conditions Assessment

The **bulk power system** can be subjected to wide range of other than normal system conditions that have low probability of occurrence. One of the objectives of extreme system conditions assessment is to determine, through planning studies, the impact of these conditions on expected steady-state and dynamic system performance. This is done in order to obtain an indication of system robustness or to determine the extent of a widespread system **disturbance**. Each Transmission Planner and Planning Coordinator has the responsibility to incorporate special simulation testing to assess the impact of extreme system conditions.

Analytical studies shall be conducted to determine the effect of design **contingencies** under the following extreme conditions:

a. Peak **load** conditions resulting from extreme weather conditions with applicable **rating** of electrical **elements**.

b. Generating unit(s) fuel shortage, (i.e. gas supply adequacy)

After due assessment of extreme system conditions, measures may be utilized, where appropriate, to mitigate the consequences that are indicated as a result of testing for such system conditions. .

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 satisfactorily 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 any other portion of the document such as Links glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document.

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
Bulk Power System Protection Criteria (Directory#4)
Emergency Operations (NPCC Directory #2)
Special Protection Systems (Directory #7))

Appendix A - Definition of Terms

Applicable emergency limits - These limits depend on the duration of the occurrence, and on the policy of the various member systems of NPCC regarding loss of life to equipment, voltage limitations, etc.

Emergency limits are those which can be utilized for the time required to take corrective action, but in no case less than five minutes.

The limiting condition for voltages should recognize that voltages should not drop below that required for suitable system **stability** performance, and should not adversely affect the operation of the **bulk power system**.

The limiting condition for equipment loadings should be such that cascading outages will not occur due to operation of protective devices upon the failure of facilities. (Various definitions of equipment **ratings** are found elsewhere in this glossary.)

Bulk power system **-** The interconnected electrical systems within north-eastern North America comprising **generation** and transmission facilities on which **faults** or **disturbances** can have a **significant adverse impact** outside of the local area. In this context, local areas are determined by the Council members.

Contingency - An event, usually involving the loss of one or more **elements,** which affects the **power** system at least momentarily.

NPCC Specific Definitions:

NPCC Emergency Criteria **Contingencies** - The set of **contingencies** to be observed when operating the **bulk power system** under **emergency** conditions. (Document C-1; also reference Document A-2, Section 6.2 - Emergency Transfers.)

NPCC Normal Criteria **Contingencies** - The set of **contingencies** to be observed when operating the **bulk power system** under normal conditions. (Document C-1; also reference Document A-2, Section 6.1 - Normal Transfers.)

Double Element Contingency - A **contingency** which involves the loss of two **elements**. (Document C-1)

Single Contingency - A single event which may result in the loss of one or more **elements.**

Single Element Contingency - A **contingency** involving the loss of one **element**. (Document C-1)

Limiting Contingency - The **contingency** which establishes the **transfer capability**. (Document C-1)

First Contingency Loss - The largest **capacity** outage including any assigned Ten-Minute Reserve which would result from the loss of a single **element** (Documents A-6 and C-1)

Second Contingency Loss - The largest **capacity** outage which would result from the loss of a single **element** after allowing for the First Contingency Loss. (Documents A-6 and C-1)

Disturbance - Severe oscillations or severe step changes of current, voltage and/or frequency usually caused by **faults**.

System Disturbance - An event characterized by one or more of the following phenomena: the loss of **power** system **stability**; cascading outages of circuits; oscillations; abnormal ranges of frequency or voltage or both.

Element - Any electric device with terminals that may be connected to other electric devices, such as a generator, transformer, circuit, circuit breaker, or bus section.

Limiting Element - The element that is either operating at its appropriate **rating** or would be, following a limiting **contingency** and, as a result, establishes a system limit.

Emergency - Any abnormal system condition that requires automatic or manual action to prevent or limit loss of transmission facilities or **generation** supply that could adversely affect the **reliability** of the electric system.

Specific to NPCC: An **Emergency** is considered to exist in an Area if **firm load** may have to be shed.

Fault Clearing

Delayed fault clearing - Fault clearing consistent with correct operation of a breaker failure **protection group** and its associated breakers, or of a backup **protection group** with an intentional time delay.

High speed fault clearing - Fault clearing consistent with correct operation of high speed relays and the associated circuit breakers without intentional time delay.
Notes: The specified time for high-speed relays in present practice is 50 milliseconds (three cycles on a 60Hz basis) or less. [IEEE C37.100-1981]. For planning purposes, a total clearing time of six cycles or less is considered high speed.

Normal fault clearing - Fault clearing consistent with correct operation of the **protection system** and with the correct operation of all circuit breakers or other automatic switching devices intended to operate in conjunction with that **protection system**.

Load - The electric **power** used by devices connected to an electrical generating system. (IEEE Power Engineering). Also see **Demand**.

<u>NPCC Specific Definitions:</u>

Firm Load - Loads that are not **Interruptible Loads**.

Interruptible Load - Loads that are interruptible under the terms specified in a contract.

Power

Apparent Power - The product of the volts and amperes. It comprises both *real* and *reactive* power, usually expressed in kilovoltamperes (kVA) or megavoltamperes (MVA).

Reactive Power - The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, **synchronous condensers**, or electrostatic equipment such as capacitors. Reactive power directly influences electric system voltage. It is usually expressed in kilovars (kVAr) or megavars (MVAr).

Real Power - The rate of producing, transferring, or using electrical energy, usually expressed in kilowatts (kW) or megawatts (MW).

Protection - The provisions for detecting power system **faults** or abnormal conditions and taking appropriate automatic corrective action.

Protection group - A fully integrated assembly of **protective relays** and associated equipment that is designed to perform the specified protective functions for a power system **element**, independent of other groups.

Notes:
(a) Variously identified as Main Protection, Primary Protection, Breaker Failure Protection, Back-Up Protection, Alternate Protection, Secondary Protection, A Protection, B Protection, Group A, Group B, System 1 or System 2.

(b) Pilot protection is considered to be one protection group. Protection system
Element Basis One or more protection groups; including all equipment such as instrument transformers, station wiring, circuit breakers and associated trip/close modules, and communication facilities; installed at all terminals of a power system **element** to provide the complete protection of that **element**.

Terminal Basis
One or more protection groups, as above, installed at one terminal of a power system **element**, typically a transmission line.

Pilot Protection - A form of line protection that uses a communication channel as a means to compare electrical conditions at the terminals of a line.

Rating - The operational limits of an electric system, facility, or **element** under a set of specified conditions.

Reclosing

Autoreclosing - The automatic closing of a circuit breaker in order to restore an **element** to service following automatic tripping of the circuit breaker. Autoreclosing does not include automatic closing of capacitor or reactor circuit breakers.

High-speed autoreclosing - The autoreclosing of a circuit breaker after a necessary time delay (less than one second) to permit **fault** arc deionization with due regard to coordination with all **relay** protective systems. This type of autoreclosing is generally not supervised by voltage magnitude or phase angle.

Manual Reclosing - The closing of a circuit breaker by operator action after it has been tripped by **protective relays**. Operator initiated closing commands may originate from local control or from remote (supervisory) control. Either local or remote close commands may be supervised or unsupervised.

Supervision- A closing command is said to be supervised if closing is permitted to occur only if certain prerequisite conditions are met (e.g., **synchronism-check**).

Synchronism-check - refers to the determination that acceptable voltages exist on the two sides of the breaker and the phase angle between them is within a specified limit for a specified time.

Relay - An electrical device designed to respond to input conditions in a prescribed manner and after specified conditions are met to cause contact operation or similar abrupt change in associated electric control circuits. (Also: see **protective relay**).

Reliability - The degree of performance of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system — **Adequacy** and **Security**.

> Adequacy — The ability of the electric system to supply the aggregate electrical **demand** and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system **elements**.
>
> Security — The ability of the electric system to withstand **disturbances** such as electric **short circuits** or unanticipated loss of system **elements**.

Reserve - In normal usage, reserve is the amount of **capacity** available in excess of the **demand**

Reserve Requirement - That capability above firm system **demand** required to provide for regulation, **load** forecasting error, equipment forced and scheduled outages, and local area supply **adequacy**

NPCC Specific Definitions:

Non-Synchronized Reserve — That portion of operating capacity which is available by synchronizing a generator to the network, and that capacity which can be made available by reducing load that is dependent on starting a generator to replace energy that is supplied from the grid. Non-Synchronized Reserve also includes the capacity achieved through the implementation of voltage reduction. (Documents A-6 and C-1)

Operating Reserve - The sum of **ten-minute** and **thirty-minute reserve**. (Documents A-3, A-6, and A-1)

Reserve on **Automatic Generation Control (AGC)** - That portion of **synchronized reserve** which is under the command of an automatic controller to respond to **load demands** without need for manual action. (Documents A-6 and C-1)

Synchronized Reserve - The unused capacity from resources that are synchronized to the system and ready to achieve claimed capacity (Documents A-6 and C-1)

Ten-minute reserve - The sum of **synchronized** and **non-synchronized reserve** that is fully available in ten minutes. (Documents A-6 and C-1)

Thirty-Minute Reserve - The sum of synchronized and non-synchronized reserve that can be utilized within thirty minutes of receiving an activation request, excluding capacity assigned to ten minute reserve. (A-6, C-1)

Resource - Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load.

Significant adverse impact - With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from **faults** or **disturbances**, shall be deemed as having **significant adverse impact**:

a. instability:
- any instability that cannot be demonstrably contained to a well defined local area,
- any loss of synchronism of generators that cannot be demonstrably contained to a well-defined local area.

b. unacceptable system dynamic response:

• an oscillatory response to a contingency that is not demonstrated to be clearly positively damped within 30 seconds of the initiating event.

c. unacceptable equipment tripping:

• tripping of an un-faulted **bulk power system** element (element that has already been classified as **bulk power system**) under planned system configuration due to operation of a protection system in response to a stable power swing,

• the operation of a Type I or Type II **Special Protection System** in response to a condition for which its operation is not required

d. voltage levels in violation of **applicable emergency limits**;

e. loadings on transmission facilities in violation of **applicable emergency limits**.

Special Protection System (SPS) – A protection system designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted elements. Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages or power flows. Automatic underfrequency load shedding as defined in the NPCC Directory #2 - Emergency Operations - is not considered a SPS. Conventionally switched, locally controlled shunt devices are not **special protection systems**.

Stability - The ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or **disturbances**.

Small-Signal Stability - The ability of the electric system to withstand small changes or **disturbances** without the loss of synchronism among the synchronous machines in the system.

Transient Stability - The ability of an electric system to maintain synchronism between its parts when subjected to a **disturbance**, and to regain a state of equilibrium following that **disturbance**.

Appendix B - Guidelines and Procedures for NPCC Area Transmission Reviews

1.0 Introduction

NPCC has established a Reliability Assessment Program to bring together work done by NPCC, Transmission Planners and Planning Coordinators relevant to the assessment of **bulk power system 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 transmission system of each Planning Coordinator Area of NPCC and the transmission interconnections to other Planning Coordinator Areas. 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 *Design and Operation of the Bulk Power System* (Directory #1). Since it is the intention of the NPCC that the *Basic Criteria* in Directory #1 be consistent with the NERC *Standards*, conformance with the NPCC *Basic Criteria* in Directory #1 assures consistency with the NERC *Standards*.

To assist the TFSS in carrying out this charge, each NPCC Planning Coordinator shall conduct an annual assessment of the **reliability** of the planned bulk power transmission system within the Planning Coordinator Area and the transmission interconnections to other Planning Coordinator Areas (an Area Transmission Review), in accordance with these Guidelines, and present a report of this assessment to the TFSS for review. Each Planning Coordinator is also responsible for providing an annual report to the Compliance Committee in regard to its Area Transmission Review in accordance with the *NPCC Reliability Compliance and Enforcement Program* (Document A-8).

The NPCC role in monitoring conformance with the NPCC *Basic Criteria* in Directory #1 is limited to those instances where non-conformance could result in adverse consequences to more than one Planning Coordinator Area. If in the process of conducting the **reliability** review; problems of an intra-Reliability Coordinator Area nature are identified, NPCC shall inform the affected systems and the Planning Coordinator within which the systems are located, but follow-up concerning resolution of the problem shall be the Planning Coordinators responsibility and not that of NPCC. The affected Planning Coordinator will notify NPCC on a timely basis as to the resolution of the identified problem. If the problem is of an inter-Reliability Coordinator Area nature, NPCC shall inform the affected Planning Coordinators and, further, shall take an active role in following-up resolution of the identified problem.

2.0 Purpose of Area Review Presentation

The purpose of the presentation associated with an Area Transmission Review is to demonstrate that the Planning Coordinators planned transmission system, based on its projection of available **resources**, is in conformance with the NPCC *Basic Criteria* in Directory #1. 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. Analysis of this material should include a review of **Special Protection Systems**, as well as an assessment of the potential for widespread cascading due to overloads, instability or voltage collapse. In addition, the potential consequences of failure or misoperation of Dynamic Control Systems (DCS), which include Transmission Control Devices as defined in the NERC *Standards*, should be addressed.

This review by the TFSS does not alter Planning Coordinators and/or Company responsibilities with respect to their system's conformity with the NPCC *Basic Criteria* in Directory #1.

3.0 The Study Year to be considered

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

4.0 Types and Frequency of Reviews

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 transmission system, and includes sufficient analyses to fully address all aspects of an Area Transmission Review as described in Section 5.0. A Comprehensive Review is required of each Planning Coordinator at least every five years. TFSS may require a Planning Coordinator to present a Comprehensive Review in less than five years if changes in the Planning Coordinator’s planned facilities or forecasted system conditions (system changes) warrant it.

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. If the system changes are major or pervasive, the Planning Coordinator should conduct a Comprehensive Review.

In March of each year, each Planning Coordinator shall present to the TFSS a proposal for the type of review to be conducted that year. TFSS will consider each Planning Coordinator's proposal and 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. Area Interim Review reports shall be presented to TFSS by the end of that calendar year, and Area Intermediate and Comprehensive Review reports shall be presented to TFSS by April of the following year.

5.0 Format of Presentation – Comprehensive and Intermediate Review

Introduction

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

- Discuss projected firm transfers and interchange schedules.

Study results demonstrating conformance with Section 5.4 of NPCC Directory #1, *Design and Operation of the Bulk Power System* entitled, "Transmission Design Criteria", which includes evaluation of contingencies after any critical generator, transmission circuit, transformer, series or shunt compensating device or HVDC pole has already been lost.

a) Discuss 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**.

b) Steady State Assessment

- Discuss 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 the remaining simulations would produce less severe results.

- 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.

- Discuss the **load** flows showing the effects of major planned changes on the system.

- Discuss applicable transfer limits between contiguous areas.

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

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

c) Stability Assessment

Discuss and/or refer to significant studies showing the effect on the system of **contingencies** as specified in Section 5.4.1 of NPCC Directory #1, *Design and Operation of the Bulk Power System*, entitled "Stability Assessment" 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 the remaining simulations would produce less severe results.

- Nature of fault, **elements** switched, switching times.

- Plots of angles versus time for significant machines, HVdc and SVC response, voltages at significant buses and significant interface flows.

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

- Include the effects of existing and planned control devices.

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

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

d) Fault Current Assessment

- Discuss the methodology and assumptions used in the fault current assessment. (An Intermediate Review may refer to the discussion from the last Comprehensive Review.)

- Discuss instances where fault levels exceed equipment capabilities and measures to mitigate such occurrences.

- Discuss changes to fault levels at stations adjacent to other Planning Coordinator Areas.

Extreme Contingency Assessment

a) Discuss 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**.

b) Provide supporting information on the extreme **contingencies** selected for evaluation and an explanation of why the remaining simulations would produce less severe results.

c) Discuss and/or refer to significant **load** flow studies showing the base case and the post fault conditions for the **contingencies** as specified in Section 5.6 of Directory #1 entitled "Extreme Contingency Assessment". Report on the most severe **contingencies** tested.

d) Discuss and/or refer to significant **stability** studies showing the effect on the system of **contingencies** as specified in Section 5.6 of Directory #1. Report on the most severe **contingencies** tested.

e) In the case where **contingency** assessment concludes serious consequences, conduct an evaluation of implementing a change to address such **contingencies**.

Extreme System Condition Assessment

a) Discuss the scope of the analyses.

b) Discuss and/or refer to significant **load** flow studies showing the effect on the steady state performance of extreme system conditions as specified in Section 5.7 of Directory #1, entitled "Extreme System Condition Assessment". Report on the most severe system conditions and **contingencies** tested.

c) Provide supporting information on the **contingencies** selected for evaluation and an explanation of why the remaining simulations would produce less severe results.

d) Discuss and/or refer to significant **stability** studies showing the effect on the dynamic performance of extreme system conditions as specified in Section 5.7 of Directory #1. Report on the most severe system conditions and **contingencies** tested.

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

Review of Special Protection Systems (SPSs)

a) Discuss 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.

b) For those **SPSs** whose failure or misoperation has an inter-Planning Coordinator Area or interregional effect, discuss and/or refer to appropriate **load** flow and **stability** studies analyzing the consequences.

c) For those **SPSs** whose failure or misoperation has only local or inter-company consequences, discuss and/or refer to **load** flow and **stability** studies demonstrating that this is still the case for the time period being reviewed.

d) 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 Forces 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.

Review of Dynamic Control Systems (DCSs)

For those DCSs whose failure or misoperation may have an inter-Planning Coordinator Area or interregional effect, discuss and/or refer to appropriate **stability** studies analyzing the consequences of such failure or misoperation in accordance with the Joint Working Group (JWG)-1 report, "Technical Considerations and Suggested Methodology for the Performance Evaluation of Dynamic Control Systems". A Comprehensive Review should address all potentially impactive existing and new DCSs, but an Intermediate Review may focus on new DCSs and just those existing DCSs that may have been impacted by system changes since they were last reviewed.

Review of Exclusions to the *Basic Criteria*.

Review any exclusions granted under the NPCC *Guidelines for Requesting Exclusions to Sections 5.4.1(b) and 5.5.1(b) Directory #1 Design and Operation of the Bulk Power System* (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.

Overview Summary of System Performance for Year Studied

6.0 Format of Presentation - Interim Review

Introduction of Interim Review

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

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

a) **Load** Forecast

b) Generation **Resources**

c) Transmission Facilities

d) **Special Protection Systems**

e) Dynamic Control Systems

f) Exclusions

Brief Impact Assessment and Overview Summary

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

7.0 Documentation

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

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

8.0 Task Force Follow-Up Procedures

8.1 Once a Planning Coordinator has presented its Review report to the TFSS, TFSS will review the Planning Coordinator's report and any supporting documentation and:

a. Consider whether to accept the report as complete and in full conformance with these Guidelines. 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. Consider their concurrence with the results and conclusion(s) of the Planning Coordinator's Review. If there is not concurrence, 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 shall prepare a summary of the results of its review, including a discussion of the Planning Coordinators of disagreement.

8.2 If the results of the Area Review indicates that the Planning Coordinator's planned bulk power transmission system is not in conformance with NPCC Directory #1, TFSS will request the Planning Coordinator to develop a plan to achieve conformance with the Criteria.

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

8.4 Upon completion of an Area Review, TFSS will report the results of the review to the Task Force on Coordination of Planning and to the Reliability Coordinating Committee.

Attachment A

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 **reliability** 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 Planning Coordinators that concentrate on individual or a limited number of facilities. This procedure applies to NPCC Overall and Area Transmission Reviews, and may be applicable to other **reliability** studies conducted by the 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 **reliability** studies in which NPCC is an active participant, to the extent that this is possible within the framework of such multi-regional efforts.

2.0 Choosing Contingencies for Testing

The ECs are defined in the NPCC Directory #1- Design and Operation of the **Bulk Power System**, and in the NERC Standards. Testing should focus on those ECs expected to have the greatest potential effect on the interconnected system. Particular attention should be paid to contingencies which would result in major angular power shifts, e.g., interruption of shorter transmission paths carrying heavy power flows, leaving longer transmission paths as the only remaining paths. Additionally, contingencies which would result in reversal of major power transfers, e.g., loss of major ties in a neighboring region or Area when said region or Area was transferring power away from the area of interest, should be considered for their impact in subjecting the system to severe power swings (reference EC type “f”). In considering specific **contingencies** to be investigated in an NPCC **reliability** study, all relevant testing done at the 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 Planning Coordinator, based on a reasonable surmise that the requesting Planning Coordinator may be adversely affected.

3.0 Modeling Assumptions

The assumed generation dispatch is a major consideration in all EC testing. In general, EC testing should use a dispatch pattern considered to be highly probable for the year and **load** level being studied. Intra-Reliability Coordinator Area inter-Reliability Coordinator Area and, where appropriate, inter-regional transfers should be simulated at a level which is experienced or expected at least 75% of the time on a flow duration basis, up to the maximum operating limit for the interfaces being tested. It is not the NPCC intent to test the worst imaginable extreme, but EC tests should be severe.

Each Planning Coordinator shall specify the appropriate Planning Coordinator **load** representation (e.g. active and reactive power as a function of voltage) for use in NPCC **reliability** studies. This applies to long term stability tests or post-transient loadflows as well as **transient stability** tests.

4.0 Evaluating Individual Test Results

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

1. Lines or transformers loaded above **short time emergency ratings**,

2. Buses with voltage levels in violation of **applicable emergency limits**, (which vary depending on the location within the system),

3. Magnitude and geographic distribution of such overloads and voltage violations across the system,

4. Transient generator angles, frequencies, voltages and power,

5. Operation of Dynamic Control Systems and **Special Protection Systems** (SPS),

6. Oscillations that could cause generators to lose synchronism or lead to dynamic instability,

7. net loss of source resulting from any combination of loss of synchronism of one or more units, generation rejection or runback initiated by SPS, or any other defined system separation,

8. Identification of the extent of the Planning Coordinator Area (s) involved for any indicated instability or islanding (the involvement of more than one

Planning Coordinator Area, should be a major consideration),

9. **Relay** operations or the proximity of apparent impedance trajectories to **relay** trip characteristics,

10. The angle across opened breakers,

11. Adequacy of computer simulation models and data.

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

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

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

5.0 Evaluating the Results of a Program of EC Testing

The NPCC Directory #1 document - "*Design and Operation of **Bulk Power System***", calls for testing of Extreme **Contingencies** (EC) "as a measure of system strength." The results of all NPCC **reliability** studies are made available to the Planning Coordinators as a guide for planners and designers in the conduct of their future work. The focus of NPCC reports, then, should be on indicating 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 **reliability** studies and/or 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 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 Planning Coordinator or Planning Coordinators 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 resource adequacy assessment 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.

Resources refer to the total contributions provided by supply-side and demand-side facilities and actions. Supply-side facilities include all generation sources within a Planning Coordinator Area and firm capacity backed purchases from neighboring systems. Demand-side facilities include measures for reducing or shifting **load**, such as conservation, **load** management, interruptible **loads**, dispatchable **loads** and small identified generation which is not metered at the control centers.

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 the NPCC Basic Criteria in Directory #1. However, the NPCC Basic Criteria provides a reference point against which a Planning Coordinator’s **resource** adequacy criterion can be compared.

The NPCC will not duplicate reviews and studies completed by member systems and Planning Coordinators**.** The NPCC may reference these reviews in appropriate NPCC reports.

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 -

Design Criteria, as defined NPCC Directory #1, over the time period under consideration. The review by the Task Force on Coordination of Planning does not replace Planning Coordinator and/or company responsibility to assess their systems in conformity with the NPCC Basic Criteria in Directory #1.

3.0 Time Period to be Considered

The time period to be considered for a Planning Coordinator's Comprehensive **Resource** Review will be five years and be undertaken every three years. In subsequent years, the Planning Coordinator shall conduct Annual Interim Reviews that will cover, at a minimum, the remaining years studied in the Comprehensive Review. Based on the results of the Annual Interim Review, the Task Force may recommend that the Planning Coordinator conduct the next Comprehensive Review at a date earlier than specified above. Comprehensive and Interim reviews are normally expected to be presented to the Task Force before the beginning of the first time period covered by the assessment.

4.0 Format of Presentation and Report – Comprehensive Review

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

4.1 Executive Summary

4.1.1 Briefly illustrate the major findings of the review.

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

4.2 Table of Contents

4.2.1 Include listing of all tables and figures.

4.3 Introduction

4.3.1 Reference the previous NPCC Area Review.

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

4.4 Resource Adequacy Criterion

4.4.1 State the Planning Coordinator's **resource** adequacy criterion.

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

4.4.3 Summarize **resource** requirements to meet the criteria for the time period under consideration. If interconnections to other Planning Coordinators and regions are considered in determining this requirement, indicate the value of the interconnections in terms of megawatts.

4.4.4 If the Planning Coordinator criterion is different from the NPCC criterion, provide either an estimate of the **resources** required to meet the NPCC criteria or a statement as to the comparison of the two criteria.

4.4.5 Discuss **resource** adequacy studies conducted since the previous Area Review, as appropriate.

4.5 Resource Adequacy Assessment

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

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

4.5.3 Discuss the impact of **load** and **resource** uncertainties on projected Planning Coordinator Area **reliability** and discuss any available mechanisms to mitigate potential **reliability** impacts.

4.5.4 Review the impacts that major proposed changes to market rules may have on Planning Coordinator Area **reliability**.

4.6 Proposed Resource Capacity Mix

4.6.1 Discuss any **reliability** impacts resulting from the proposed **resources** fuel supply and transportation or environmental considerations.

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

4.6.3 Discuss any **reliability** impacts related to an **Area**'s compliance with state, Federal or Provincial requirements (such as environmental, renewable energy, or greenhouse gas reductions).

5.0 Format of Presentation and Report – Annual Interim Review

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

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

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

Sections A and B should describe the **reliability** model and program used for the **resource** adequacy studies discussed in Section 4.5. Section C should describe the Task Force follow-up procedures.

A. <u>Description of Resource Reliability Model</u>

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 Procedure for verifying **ratings**. Reference NPCC Document B-9, *Guide for Rating Generating Capability*.

1.2.2 Unavailability Factors Represented

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

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

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

1.2.2.4 Tabulation of typical unavailability factors.

1.2.3 Purchase and Sale Representation.

1.2.3.1. Describe characteristics and level of dependability of transactions.

1.2.4 Retirements.

1.2.4.1 Summarize proposed retirements.

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

1.4 Modeling of Variable and Limited Energy Sources.

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

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

1.6 Modeling of all **Resources**.

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

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

1.8 Incorporate the **reliability** impacts of market rules.

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

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

C. Task Force Follow-Up Procedures

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

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

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

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

4. Recommend approval to the Reliability Coordinating Committee.

Attachment A

Appendix E - Guidelines for Requesting Exclusions to Sections 5.4.1 (B) and 5.5.1 (B) of NPCC Directory #1 – *Design and Operation of the Bulk Power System*

1.0 Introduction

The Northeast Power Coordinating Council (NPCC) was formed to promote the **reliability** and efficiency of electric service of the interconnected **bulk power system** of the members of the NPCC by extending the coordination of their system design and operations as cited in the NPCC Memorandum of Agreement. Towards that end, the Member Systems of NPCC adopted the *Basic Criteria for Design and Operation of Interconnected Power Systems* (Directory #1 – *Design and Operation of the Bulk Power System*), which establishes the minimum standards for design and operation of the interconnected **bulk power system** of NPCC. In accordance with those standards, the **bulk power system** should be designed and operated so as to withstand certain specific **contingencies**.

One such **contingency**, listed under Section 5.4.1(b), Transmission Design Criteria - **Stability** Assessment, and under Section 5.5.1(b), Transmission Operating Criteria - Normal Transfers, involves "simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with normal **fault clearing**." Although this **contingency** is normally included in the NPCC Criteria, the Basic Criteria in Directory #1 define specific conditions for which a multiple circuit tower situation is an acceptable risk and, therefore, can be excluded.

Directory #1 also allows for requests for exclusion from this **contingency**, on the basis of acceptable risk, for other instances of multi-circuit tower construction. All exclusions must be 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 Sections 5.4.1(b) and 5.5.1(b) of the Basic Criteria must include 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 a multi-circuit **contingency**;

2.3 An assessment of the consequences of the occurrence of a multi-circuit **contingency**, including, but not limited to, a discussion of levels of exposure and probability of occurrence of **significant adverse impact** outside the local area;

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

2.5 For planned facilities, the estimated frequency of multi-circuit **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 shall be used in obtaining exclusion to Sections 5.4.1(b) or 5.5.1(b) of Directory #1:

3.1 The entity requesting the exclusion (the Requestor) shall submit 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 shall review the request, verify that the documentation requirements have been met, and determine the acceptability of the request.

3.3 If TFSS deems the request acceptable, TFSS shall request 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 shall provide 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 will provide this information directly to the interested Task Force, with a copy to the TFSS. The other Task Forces shall review the request and indicate their acceptance or non-acceptance to TFSS.

3.4 If any of the four Task Forces determines the request is not acceptable, TFSS will respond to the Requestor with the determination and inform the RCC and the other Task Forces of the decision.

3.5 TFSS shall notify TFCP, TFCO, and TFSP of an exclusion that has been accepted by the Task Forces and the basis for the exclusion. The TFSS will then make a recommendation to the RCC regarding the exclusion.

3.6 The NPCC Policy for Alternative Dispute Resolution is available for use if the decision is unacceptable to the Requestor.

Upon acceptance of the requested exclusion by the RCC, TFSS shall so notify the Requestor and update a summary list of the exclusions. The summary list and supporting documents shall be maintained by NPCC.

4.0 Periodic Review of Exclusions of Record

Exclusions shall be reviewed within the Planning Coordinator’s transmission reviews as provided in *Guidelines for NPCC Area Transmission Reviews* (NPCC Directory #1 – Appendix C). This review shall verify that the basis for each exclusion is still valid. TFSS shall notify TFCP, TFCO, TFSP, and the RCC when a Planning Coordinator’s transmission review has determined exclusion is no longer applicable, and revise the exclusion summary list accordingly.

Attachment A

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

To ensure that there is effective coordination for system **reliability** concerns, this document establishes procedures for the exchange of information regarding load/capacity forecasts, including firm sales and firm purchases, generator outage schedules, and transmission outage schedules for those facilities 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, pre-arranged conference call meetings or in conference calls arranged in anticipation of problems such as capacity deficiency or inadequate light load margin in one or more RC Areas.

Participants and other recipients of the information provided by this process must adhere to the NERC *Confidentiality Agreement for Electric System Operating Reliability Data*.

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 methodology and format of the seasonal report will be presented in NPCC Document C-45, “CO-12 Seasonal Assessment Methodology,” currently under development.

The results will be reviewed by the NPCC Task Force on Coordination of Operation (TFCO) and the NPCC Reliability Coordinating Committee (RCC) in advance of the spring and autumn meetings of both groups.

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

3.0 Generator Outage Coordination

3.1 Each RC Area should exchange current and expected critical generation outages.

4.0 Transmission Outage Coordination

4.1 Advance Planning of Transmission Facility Outages

NPCC Document Directory#1, *Basic Criteria for Design and Operation of Interconnected Power Systems,* requires that scheduled outages of transmission facilities that affect **reliability** between RC Areas be coordinated sufficiently in advance of the outage to permit the affected RC Area to maintain **reliability**. For the purposes of this procedure, each RC should exchange critical transmission outages as identified in coordination agreements with their interconnected neighbors and jointly develop and maintain a Facilities Notification List.

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**.

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 approved, updated Facilities Notification List will be posted on the NPCC secure website.

The Task Force on System Protection develops yearly the list of NPCC Type 1 **special protection systems** with input from the Task Force on System Studies.

It should be noted that revisions to the Facilities Notification List only 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 Work

4.3.1 Notification requirements should be defined in interconnected coordination agreements. The time frames identified below are the minimum notification requirements.

4.3.2 The initiating RC will advise affected RCs of all applications for outages of facilities on the Facilities Notification List, including those which have been planned.

All outages to equipment listed in the Facilities Notification List should be planned with as much lead time as practical.

Normally, notification for work on facilities covered by this instruction will be submitted to the appropriate RC Areas at least two (2) working days prior to the time the facility 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. Analysis will be conducted by each RC Area in accordance with internal procedures.

4.3.3 An RC Area will not normally remove from service any transmission facility, 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 Data Providers

NPCC entities are to provide the data in order to adequately assess the reliability of the NPCC bulk power system.

6.0 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:

6.1 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 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," Attachment C, will be forwarded to the conference call participants by the NPCC Staff.

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

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

If a deficiency or light load condition, or if adverse system operating conditions are expected within the next week, any RC Area may recommend that an Emergency Preparedness Conference Call (NPCC Document C-01) take place at an appropriate time.

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

6.2 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.

6.3 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.

Attachment A

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.
Firm Purchases (Line Item 2)	Include only those transactions where capacity is delivered. Exclude "energy only" transactions.
Firm Sales (Line Item 3)	Include only those transactions where capacity is delivered. Exclude "energy only" transactions.
Net Capacity (Line Item 4)	Add Installed Generating Capacity and Firm Purchases. Subtract Firm Sales. (Line 1+Line 2-Line3)
Peak Load Forecast (Line Item 5)	The peak load forecast should be the best estimate of the RC Area's maximum peak load exposure anticipated for the week reported.
Available Reserve (Line Item 6)	Subtract Peak Load Forecast from Net Capacity. (Line 4-Line5.)
Demand Side Management (Line Item 7)	Include only maximum capability which can be obtained by operator initialization within four (4) hours.

Attachment A (continued)	
Known Unavailable Capability (Line Item 8)	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 9)	Available Reserve plus Demand Side Management minus Known Unavailable Capacity. (Line 6+Line 7-Line 8)
Required Operating Reserve (Line Item 10)	The methodology used by each RC Area in calculating operating reserve must, as a minimum, meet the requirements of NPCC Document A-06, “Operating Reserve Criteria.” Methodologies differing from the A-06 requirements should be clarified in Attachment B, “NPCC Weekly Conference Call Generating Capacity Worksheet,” under the tab for “Operating Reserve.”
Gross Margin (Line Item 11)	Subtract Required Operating Reserve from Net Reserve. (Line 9-Line 10)
Unplanned Outages (Line Item 12)	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 13)	Subtract Unplanned Outages from Gross Margin. A positive value reflects surplus reserve. A negative value reflects a deficiency. (Line 11-Line 12)
Forecast High / Low Temperatures and Days (Line Item 14)	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 15)	Include the expected high and low forecast seasonal temperatures for the RC Area.
Minimum Load Forecast (Line Item 16)	The minimum load forecast should be the best estimate of the RC Area's minimum load exposure anticipated for the week reported.
Minimum Resources (Line Item 17)	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 18)	Subtract Minimum Resources from Minimum Load Forecast. A negative number indicates a light load condition. (Line 16-Line 17)

Attachment A

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 Excel spreadsheet used each week to assist in the calculation of the data discussed during the weekly conference call. A blank template, in Microsoft Office Excel 2003, is available from the NPCC office.

Attachment A

Procedure for Operational Planning Coordination - Attachment C

CONDITIONS FOR DISCUSSION

Items of particular concern that should be discussed during a conference call 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 might have an adverse impact on internal and external energy transfers;
- potential need for emergency transfers;
- expected transfer limits and limiting elements;
- a change or anticipated change in the normal operating configuration of the system, such as the temporary modification of relay protection schemes so that the usual and customary levels of protection will not be provided, or the arming of special protection systems not normally armed, or the application of abnormal operating procedures; and
- update of the abnormal status of NPCC Type I special protection systems forced out of service.

Attachment A

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 for effective inter-Transmission Operator Area voltage control, consistent with the NPCC, Directory #1, "Design and Operation of the Bulk Power System," and applicable NERC Standards. Specific methods to implement this Procedure may vary among 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 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 Transmission Operator develops, and operates in accordance with, its own voltage control procedures and criteria which are consistent with NPCC, Inc. Criteria and NERC Standards. Adjacent Transmission Operators should be familiar with the respective criteria and procedures of their neighboring Transmission Operators should mutually agree upon procedures for inter- Transmission Operator Area voltage control. Whether inter- Transmission Operator Area voltage control is carried out through specific or general procedures, the following should be considered and applied:

2.1 To effectively coordinate voltage control, location and placement of metering for **reactive power** resources and voltage controller status should be consistent between adjacent Transmission Operators.

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- 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 real **power** transfer;

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

2.7 shunt reactive device availability and switching strategy; and

2.8 **static VAR compensator** availability, reactive **reserve**, and control strategy.

3.0 Procedure

Transmission Operators maintain normal voltage conditions, in accordance with their own individual or joint operating policies, procedures and applicable interconnection agreements. In the event the system state changes to an abnormal voltage condition, the Transmission Operator in which the abnormal condition is originating should immediately take corrective action. If the corrective control actions are ineffective, or the Transmission Operator has insufficient reactive resources to control the problem, assistance may be requested from other Transmission Operators.

3.1 Normal Voltage Conditions

The **bulk power system** is operating with Normal Voltage Conditions when:

- actual voltages are within applicable normal (pre-**contingency**) voltage ranges; and
- expected post-**contingency** voltages are within applicable post-**contingency** minimum and maximum levels following the most severe **contingency** specified in Directory #1 “Design and Operation of the Bulk Power System.”

Each Transmission Operator should maintain a mix of static and dynamic resources, including reactive **reserves**.

3.1.1 Providing that it is feasible to regulate reactive flows on its **tie lines**, each Transmission Operator should establish a mutually agreed upon voltage profile with adjacent Transmission Operators and with other neighboring systems. This voltage profile should conform to the provisions of the relevant interconnection agreements and may provide for:

- The minimum and maximum voltage at stations at or near terminals of inter-Transmission Operator Area tie lines;
- The receipt of reactive flow at one tie point in exchange for delivery at another;
- The sharing of the reactive requirements of **tie lines** and series regulating equipment (either equally or in proportion to line lengths, etc.); and
- The transfer of **reactive power** from one Transmission Operator to another.

This voltage profile, adjusted for changes in operating conditions, should be considered as the basis for determining which Transmission Operator should implement necessary measures to alleviate abnormal voltage conditions affecting more than one Transmission Operator as discussed in 3.2.10 below.

3.1.2 Each Transmission Operator should anticipate voltage trends and initiate corrective action in advance of critical periods of heavy and light **loads**.

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

4.1 On, or shortly before, the first of July, the 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 procedures and principles between the reporting Reliability Coordinator and adjacent Reliability Coordinators providing detailed application, or,

b) a copy of any new understanding, such as the minutes of an operating committee meeting between Reliability Coordinators, indicating that such detailed application is not required, and why;

c) a copy of any revisions to the procedures and principles, or understandings currently on file at NPCC, that exists between the reporting Reliability Coordinator and adjacent Reliability Coordinators;

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

4.2 The TFCO Secretary will draft a report summarizing the extent to which responses indicated conformance with the NPCC Procedures, and will forward it to TFCO members at least two weeks prior to the October TFCO meeting.

4.3 Following TFCO review and adoption, the TFCO Chairman will forward the report to the Chairman of the Reliability Coordinating Committee (RCC) recommending acceptance or other action as deemed appropriate. This will normally be forwarded three weeks prior to the next regularly scheduled RCC meeting.

Attachment B

ISO Planning Procedure No. 3,

"Reliability Standards for the New England Bulk Power Supply System."

ISO NEW ENGLAND PLANNING PROCEDURE NO. 3

RELIABILITY STANDARDS FOR THE NEW ENGLAND AREA BULK POWER SUPPLY SYSTEM

EFFECTIVE DATE: March 5, 2010

REFERENCES:

NPCC Reliability Reference Directory # 1 Design and Operation of the Bulk Power System, December 1, 2009 (Includes references to NERC ERO Reliability Standards)

NPCC Regional Reliability Reference Directory # 2 Emergency Operations, October 21, 2008

NPCC Reliability Reference Directory # 4 Bulk Power System Protection Criteria, December 1, 2009

NPCC Document A-7, Glossary of Terms, Revised July 17, 2007

NPCC Regional Reliability Reference Directory # 7 Special Protection Systems, December 27, 2007

ISO New England Planning Procedure 5-5, Special Protection Systems Application Guidelines

Damping Criterion Basis Document, Stability Task Force, Approved April 1, 2009.

NERC NUC-001-2, Nuclear Plant Interface Coordination Reliability Standard, Adopted by NERC Board of Trustees: August 5, 2009

NERC Glossary of Terms Used in Reliability Standards, Updated April 20, 2009

CONTENTS

RELIABILITY STANDARDS FOR THE NEW ENGLAND AREA BULK POWER SUPPLY SYSTEM

1. INTRODUCTION

The ISO New England Transmission, Markets and Services Tariff (the "Tariff") provides for the establishment of reliability standards for the bulk power supply system of the New England Area. The reliability standards set forth herein have been adopted as appropriate for the New England **bulk power supply system**[1]**.** Further, they are consistent with those established by the Northeast Power Coordinating Council in the NPCC "Basic Criteria for Design and Operation of Interconnected Power Systems" and the NPCC "Bulk Power System Protection Criteria."

The purpose of these New England Reliability Standards is to assure the reliability and efficiency of the New England **bulk power supply system** through coordination of system planning, design and operation. These standards apply to all entities comprising or using the New England **bulk power supply system**. The host Governance Participant (the Governance Participant through which a non-Governance Participant connects to the **bulk power supply system**) shall use its best efforts to assure that, whenever it enters into arrangements with non-Governance Participants, such arrangements are consistent with these standards.

These Reliability Standards establish minimum design criteria for the New England **bulk power supply system**. It is recognized that more rigid design and operating criteria may be applied in some segments of the pool because of local considerations. Any constraints imposed by the more rigid criteria will be taken into account in all testing. It is also recognized that the Reliability Standards are not necessarily applicable to those **elements** that are not a part of the New England **bulk power supply system**.

Because of the long lead times required for the planning and construction of generation and transmission facilities versus the short lead times available for responding to changed operating conditions, it is necessary that criteria for planning and design vary in some respects from the System Rules used in actual operations. The intent is to have the system operate at the level of reliability that was contemplated at the time it was designed. For this reason, it is necessary that the design criteria simulate the effects of the equipment outages which may be expected to occur in actual operation. Nevertheless, it should be recognized that in actual operations, it may not always be possible to achieve the design level of reliability due to delays in construction of critical facilities, excessive forced outages, or loads exceeding the predicted levels.

[1] Terms in bold typeface are defined in Appendix A.

These Reliability Standards are intended to be used for planning and design of the New England **bulk power system**. Reliability criteria and procedures for operations are detailed elsewhere, with the primary reliability-related documents used in system dispatch and operations being:

1. ISO New England Operating Procedure No. 1 – Central Dispatch Operating Responsibility and Authority of ISO New England, the Local Control Centers and Market Participants
2. ISO New England Operating Procedure No. 3 – Transmission Outage Scheduling
3. ISO New England Operating Procedure No. 4 – Action During a Capacity Deficiency
4. ISO New England Operating Procedure No. 5 – Generation Maintenance and Outage Scheduling
5. ISO New England Operating Procedure No. 6 – System Restoration
6. ISO New England Operating Procedure No. 7 – Action in an Emergency
7. ISO New England Operating Procedure No. 8 – Operating Reserve and Regulation
8. ISO New England Operating Procedure No. 11 – Black Start Capability Testing Requirements
9. ISO New England Operating Procedure No. 12 – Voltage and Reactive Control
10. ISO New England Operating Procedure No. 13 – Standards for Voltage Reduction and Load Shedding Capability
11. ISO New England Operating Procedure No. 14 – Technical Requirements for Generators, Demand Resources and Asset Related Demands
12. ISO New England Operating Procedure No. 17 – Load Power Factor Correction
13. ISO New England Operating Procedure No. 18 – Metering and Telemetering Criteria
14. ISO New England Operating Procedure No. 19 – Transmission Operations

The New England **bulk power supply system** shall be designed for a level of reliability such that the loss of a major portion of the system, or unintentional separation of any portion of the system, will not result from reasonably foreseeable **contingencies**. Therefore, the system is required to be designed to meet representative **contingencies** as defined in these Reliability Standards. Analyses of simulations of these **contingencies** should include assessment of the potential for widespread cascading outages due to overloads, instability, voltage collapse, or the inability to meet the **Nuclear Plant Interface Requirements** (**NPIRs**). The NPIRs for each nuclear plant generator subject to dispatch by ISO New England Inc. (ISO) are documented in its ISO Form NX-12 under ISO New England Operating Procedure No. 14 – Technical Requirements for Generators, Demand Resources and Asset Related

Demands. The loss of small portions of the system may be tolerated provided the reliability of the overall interconnected system is not jeopardized and the **NPIRs** are met.

The standards outlined hereinafter are not tailored to fit any one system or combination of systems but rather outline a set of guidelines for system design which will result in the achievement of the desired level of reliability and efficiency for the New England **bulk power supply system**.

2. RESOURCE ADEQUACY

Resources will be planned and installed in such a manner that, after due allowance for the factors enumerated below, the probability of disconnecting noninterruptible customers due to **resource** deficiency, on the average, will be no more than once in ten years. Compliance with this criteria shall be evaluated probabilistically, such that the loss of load expectation [LOLE] of disconnecting noninterruptible customers due to resource deficiencies shall be, on average, no more than 0.1 day per year.

a. The possibility that load forecasts may be exceeded as a result of weather variations.

b. Immature and mature **equivalent forced outage rates** appropriate for generating units of various sizes and types, recognizing partial and full outages.

c. Due allowance for scheduled outages and deratings.

d. Seasonal adjustment of **resource** capability.

e. Proper maintenance requirements.

f. Available operating procedures.

g. The reliability benefits of interconnections with systems that are not Governance Participants.

h. Such other factors as may from time-to-time be appropriate.

For planning purposes, the assumed **equivalent forced outage rate** of a generating unit connected to the transmission network by a radial transmission line will be increased to reflect the estimated transmission line forced outage rate if significant.

The potential power transfers from outside New England that are considered in determining the New

England capacity requirements must not exceed the **emergency** inter-Area transmission transfer capabilities, as determined in accordance with Section 4.2, using long term emergency (LTE) ratings.

3. AREA TRANSMISSION REQUIREMENTS

The New England **bulk power supply system** shall be designed with sufficient transmission capacity to integrate all **resources** and serve **area** loads and meet the applicable **NPIRs** under the conditions noted in Sections 3.1 and 3.2. These requirements will also apply after any critical generator, transmission circuit, transformer, phase angle regulating transformer, HVDC pole, series or shunt compensating device has already been lost, assuming that the **area resources** and power flows are adjusted between outages, using all appropriate reserve **resources** available in ten minutes and where applicable, any phase angle regulator control, and HVDC control.

With due allowance for generator maintenance and forced outages, design studies will assume power flow conditions with applicable transfers, load, and **resource** conditions that reasonably stress the system. Transfers of power to and from another **Area**, as well as within New England, shall be considered in the design of inter-Area and intra-Area transmission facilities.

Transmission transfer capabilities will be based on the load and **resource** conditions expected to exist for the period under study and shall be determined in accordance with Section 4.1 for normal transfers, and Section 4.2 for **emergency** transfers. All reclosing facilities will be assumed in service unless it is known that such facilities have been or will be rendered inoperative.

In applying these criteria, it is recognized that it may be necessary to restrict the output of a generating station(s) and/or HVDC terminal(s) following the loss of a system **element**. This may be necessary to maintain system stability or to maintain line loadings within appropriate thermal ratings in the event of a subsequent outage. But, the system design must be such that, with all transmission facilities in service, all **resources** required for reliable and efficient system operation can be dispatched without unacceptable restriction.

Special Protection Systems (SPSs) may be employed in the design of the interconnected power system. All SPSs proposed for use on the New England system must be reviewed by the Reliability Committee and NPCC and approved by the ISO. Some SPSs may also require acceptance by NPCC. The requirements for the design of SPSs are defined in the NPCC "Bulk Power System Protection Criteria" and the NPCC "Special Protection System Criteria". A set of guidelines for application of SPSs on the New England system are contained in the ISO New England Planning Procedure 5-6 “Special Protection Systems Application Guidelines”.

3.1 STABILITY ASSESSMENT

The New England **bulk power supply system** shall remain stable and damped in accordance with the criterion specified in Appendix C during and following the most severe of the **contingencies** stated below **with due regard to reclosing**, and before making any manual system adjustments. For each of the **contingencies** below that involves a fault, stability and damping in accordance with the criterion specified in Appendix C 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** where such protection group is required or where there would otherwise be a significant adverse impact outside the local area.

a. A permanent three-phase fault on any generator, transmission circuit, transformer, or bus section with **normal fault clearing**.

b. Simultaneous permanent phase-to-ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit transmission tower, with **normal fault clearing**. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition and other similar situations can be excluded on the basis of acceptable risk, provided that the ISO specifically approves each request for exclusion. Similar approval must be granted by the NPCC Reliability Coordinating Committee.

c. A permanent phase-to-ground fault on any transmission circuit, transformer or bus section with **delayed fault clearing**. This **delayed fault clearing** could be due to circuit breaker, relay system or signal channel malfunction.

d. Loss of any **element** without a fault.

e. A permanent phase-to-ground fault in a circuit breaker, with **normal fault clearing**. (**Normal fault clearing** time for this condition may not be high speed.)

f. Simultaneous permanent loss of both poles of a **direct current bipolar** facility without an ac fault.

g. The failure of any SPS which is not functionally redundant to operate properly when required following the **contingencies** listed in "a" through "f" above.

h. The failure of a circuit breaker to operate when initiated by an SPS following: loss of any **element** without a fault; or a permanent phase to ground fault, with **normal fault clearing**, on any transmission circuit, transformer, or bus section.

3.2 STEADY STATE ASSESSMENT

a. Adequate reactive power resources with reserves and appropriate controls shall be installed to maintain voltages within normal limits for pre-disturbance conditions, and within **applicable emergency limits** for the system conditions that exist following the **contingencies** specified in Section 3.1.

b. Line and equipment loadings shall be within normal limits for pre-disturbance conditions and within **applicable emergency limits** for the system load and generation conditions that exist following the **contingencies** specified in Section 3.1.

3.3 FAULT CURRENT ASSESSMENT

The New **England bulk power supply system** shall be designed to ensure equipment capabilities are adequate for fault current levels with all transmission and generation facilities in service for all potential operating conditions.

4. TRANSMISSION TRANSFER CAPABILITY

The New England **bulk power supply system** shall be designed with adequate inter-Area and intra-Area transmission transfer capability to minimize system reserve requirements, facilitate transfers, provide **emergency** backup of supply **resources**, permit economic interchange of power, and to assure that the conditions specified in Sections 3.1 and 3.2 can be sustained without adversely affecting the New England system or other **Areas** and without violating the **NPIRs**. Anticipated transfers of power from one **area** to another, as well as within **areas**, should be considered in the design of inter-Area and intra-Area transmission facilities. Therefore, design studies will assume applicable transfers and the most severe load and **resource** conditions that can be reasonably expected.

Firm transmission transfer capabilities shall be determined for Normal and **Emergency** transfer conditions as defined in Sections 4.1 and 4.2. Normal transfer conditions are to be assumed except during an **Emergency** as defined by Item 7 in Appendix A. In determining the **emergency** transfer capabilities, a less conservative margin is justified.

4.1 NORMAL TRANSFERS

For normal transfer conditions the New England **bulk power supply system** shall remain stable and damped in accordance with the criterion specified in Appendix C in during and following the most severe of the conditions specified in Section 3.1 "a" through "h", **with due regard to reclosing**, and before making any manual system adjustments.

Voltages, line loadings and equipment loadings shall be within normal limits for pre-disturbance conditions and within **applicable emergency limits** for the system load and **resource** conditions that exist following any disturbance specified in Section 3.1.

4.2 EMERGENCY TRANSFERS

For **emergency** transfer conditions the New England **bulk power supply system** shall remain stable and damped in accordance with the criterion specified in Appendix C during and following the most severe of the **contingencies** stated in "a" and "b" below. **Emergency** transfer levels may require adjustment of **resources** and, where available, phase angle regulator controls and HVDC controls, before manually reclosing faulted **elements**.

a. A permanent three-phase fault on any generator, transmission circuit, transformer, or bus section, with **normal fault clearing** and **with due regard to reclosing**.

b. Loss of any **element** without a fault.

For **emergency** transfer conditions the pre-disturbance voltages, line, and equipment loadings shall be within **applicable emergency limits**. The post-disturbance voltages, line, and equipment loadings shall be within **applicable emergency limits** immediately following the **contingencies** above.

5. EXTREME CONTINGENCY ASSESSMENT

Extreme **contingency** assessment recognizes that the New England **bulk power system** can be subjected to events which exceed in severity the **contingencies** listed in Section 3.1. Planning studies will be conducted to determine the effect of the following extreme **contingencies** on New England **bulk power supply system** performance as a measure of system strength. Plans or operating procedures will be developed, where appropriate, to reduce the probability of occurrence of such **contingencies**, or to mitigate the consequences that are indicated as a result of the simulation of such **contingencies**.

a. Loss of the entire capability of a generating station.

b. Loss of all transmission circuits emanating from a generating station, switching station, dc terminal or substation.

c. Loss of all transmission circuits on a common right-of-way.

d. Permanent three-phase fault on any generator, transmission circuit, transformer or bus section, with **delayed fault clearing** and **with due regard to reclosing**. This **delayed fault clearing** could be due to circuit breaker, relay system or signal channel malfunction.

e. The sudden dropping of a large load or major load center.

f. The effect of severe power swings arising from disturbances outside of New England.

g. Failure of a **Special Protection System** to operate when required following the normal **contingencies** listed in Section 3.1 "a" through "f".

h. The operation or partial operation of a **Special Protection System** for an event or condition for which it was not intended to operate.

i. Common mode failure of the fuel delivery system that would result in the sudden loss of multiple plants (i.e. gas pipeline **contingencies**, including both gas transmission lines and gas mains).

6. EXTREME SYSTEM CONDITIONS ASSESSMENT

The New England **bulk power supply system** can be subjected to a wide range of other than normal system conditions that have low probability of occurrence. One of the objectives of extreme system conditions assessment is to determine through planning studies, the impact of these conditions on expected steady-state and dynamic system performance. This is done in order to obtain an indication of system robustness or to determine the extent of a widespread adverse system response.

Analytical studies will be conducted to determine the effect of design contingencies under the following extreme system conditions:

a. Peak load conditions resulting from extreme weather conditions with applicable rating of electrical elements.

b. Generating unit(s) fuel shortage, (e.g. gas supply unavailability).

After due assessment of extreme system conditions, measures may be utilized, where appropriate, to mitigate the consequences that are indicated as a result of testing for such extreme system conditions.

Document History[2]

Rev. 0 Rec.: RTPC - 6/8/99; App.: NEC - 7/9/99
Rev. 1 Rec.: RC - 12/7/04; App.: PC - 1/7/05
Rev. 2 Eff.: 2/1/05
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Rev. 4 Rec.: RC – 5/19/09; Rec.:PC – 6/05/09; Eff. 6/11/09
Rev. 5 Modifications Only Address NERC Standard NUC-001-2
Rec.: RC – 2/26/10; Rec. PC – 3/05/10; Eff. 3/05/10

[2] This Document History documents action taken on the equivalent NEPOOL Procedure prior to the RTO Operations Date as well as revisions to the ISO New England Procedure subsequent to the RTO Operations Date.

APPENDIX "A"

LIST OF DEFINITIONS

1. **APPLICABLE EMERGENCY LIMIT**
   These **emergency** limits depend on the duration of the occurrence, and are subject to New England standards.

   Emergency limits are those which can be utilized for the time required to take corrective action, but in no case less than five minutes.

   The limiting condition for voltages should recognize that voltages should not drop below that required for suitable system stability performance, meet the **Nuclear Plant Interface Requirements** and should not adversely affect the operation of the New England **bulk power supply system**.

   The limiting condition for equipment loadings should be such that cascading outages will not occur due to operation of protective devices upon the failure of facilities.

2. **AREA**
   An Area (when capitalized) refers to one of the following: New England, New York, Ontario, Quebec or the Maritimes (New Brunswick, Nova Scotia and Prince Edward Island); or, as the situation requires, area (lower case) may mean a part of a system or more than a single system.

3. **BULK POWER SUPPLY SYSTEM**
   The New England interconnected bulk power supply system is comprised of generation and transmission facilities on which faults or disturbances can have a significant effect outside of the local **area**.

4. **CONTINGENCY** (as defined in NPCC Document A-7)
   An event, usually involving the loss of one or more **elements**, which affects the power system at least momentarily.

5. **DELAYED FAULT CLEARING** (as defined in NPCC Document A-7)
   Fault clearing consistent with correct operation of a breaker failure **protection group** and its associated breakers, or of a backup **protection group** with an intentional time delay.

6. **ELEMENT** (as defined in NPCC Document A-7)
Any electric device with terminals which may be connected to other electric devices, usually limited to a generator, transformer, circuit, circuit breaker, or bus section.

7. **EMERGENCY**
An emergency is considered to exist if firm load may have to be reduced because sufficient capacity or energy is unavailable after due allowance for purchases. Emergency transfers are applicable under such conditions. The emergency is considered to exist as long as any firm system load is potentially or actually curtailed.

8. **EQUIVALENT FORCED OUTAGE RATE**
The equivalent forced outage rate (EFOR) is the ratio of total time a generator is completely forced out of service plus the equivalent full outage time of any forced partial restrictions, to the total time that the unit is not on scheduled maintenance.

9. **HVDC SYSTEM, DIRECT CURRENT BIPOLAR**
An HVDC system with two poles of opposite polarity.

10. **NORMAL FAULT CLEARING** (as defined in NPCC Document A-7)
Fault clearing consistent with correct operation of the **protection system** and with the correct operation of all circuit breakers or other automatic switching devices intended to operate in conjunction with that **protection system**

11. **NUCLEAR PLANT INTERFACE REQUIREMENTS** (as defined in the NERC Glossary of Terms Used in Reliability Standards and as documented in ISO Form NX12)

12. **PROTECTION GROUP** (as defined in NPCC Document A-7)
A fully integrated assembly of **protective relays** and associated equipment that is designed to perform the specified protective functions for a power system **element**, independent of other groups.

Notes:

a) Variously identified as Main Protection, Primary Protection, Breaker Failure Protection, Back-Up Protection, Alternate Protection, Secondary Protection, A Protection, B Protection, Group A, Group B, System 1 or System 2.
b) Pilot protection is considered to be one protection group.

13. **PROTECTION SYSTEM** (as defined in NPCC Document A-7)
Element Basis: One or more protection groups; including all equipment such as instrument transformers, station wiring, circuit breakers and associated trip/close modules, and communication facilities; installed at all terminals of a power system **element** to provide the

complete protection of that **element**.

Terminal Basis: One or more protection groups, as above, installed at one terminal of a power system **element**, typically a transmission line.

14. **RESOURCE**
Resource refers to a supply side or demand-side facility and/or action. For the purposes of this procedure, resource means a generating unit, a Demand Resource, a Dispatchable Load, an External Resource or an External Transaction. Demand Resource, Dispatchable Load, External Resource and External Transaction are as defined in Market Rule 1.

15. **SPECIAL PROTECTION SYSTEM (SPS)** (as defined in NPCC Document A-7)
A **protection system** designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted **elements**. Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages or power flows. Automatic under frequency load shedding, as defined in NPCC Emergency Operation Criteria A-3, is not considered an SPS. Conventionally switched, locally controlled shunt devices are not SPSs.

16. **TEN-MINUTE RESERVE** (as defined in NPCC Document A-7)
The sum of synchronized and non-synchronized reserve that is fully available in ten minutes.

17. **WITH DUE REGARD TO RECLOSING** (as defined in NPCC Document A-7)
This phrase means that before any manual system adjustments, recognition will be given to the type of reclosing (i.e., manual or automatic) and the kind of protection.

APPENDIX "B"

GENERAL GUIDELINES FOR DEMONSTRATING COMPLIANCE WITH PLANNING PROCEDURE NO. 3, RELIABILITY STANDARDS FOR THE NEW ENGLAND AREA BULK POWER SUPPLY SYSTEM

General guidelines for demonstrating compliance with criteria are outlined as follows:

- Testing should be performed to examine the performance of the system. This could be done using "standard" deterministic approaches, and must consider a sufficient range of reasonably stressed system conditions. A consensus of appropriate review groups would be required regarding the adequacy of the system test conditions.

- To demonstrate compliance with criteria:

  - Identify there are no operational restrictions, with all lines in service

    and

    all load can be served by available **resources** (allowing full use of **ten-minute reserve**, phase shifters, HVDC control, etc.) with any facility assumed already forced out of service.

    or

  - If there are operational restrictions or conditions for which all load can not be served:
    1) Determine the predicted frequency, duration, period, and magnitude of the restrictions.
    2) Convert these findings into a statement describing their effects upon the Governance Participants.
    3) Establish the impact of these effects on the reliable and efficient operation of the **bulk power supply system**.

  Appropriate review groups will determine the acceptability of restrictions, based on the facts established.

This approach is based on the premise that compliance can be demonstrated if there are no conceivable problems or if it can be proven that potential problems are not significant. As stated, there must be agreement that a sufficient range of system conditions has been analyzed. The significance of any identified problems must be clearly and adequately described; the degree of analysis required will depend on the problem. It may be possible to evaluate the significance of some apparently minor problems by simple means. Problems which appear to be of greater concern may require more substantial and rigorous analysis.

APPENDIX "C"

DAMPING CRITERION

The purpose of the damping criterion is to assure small signal stability of the New England **bulk power supply system**. System damping is characterized by the damping ratio, zeta (ζ). The damping ratio provides an indication of the length of time an oscillation will take to dampen. The damping criterion specifies a minimum damping ratio of 0.03, which corresponds to a 1% settling time of one minute or less for all oscillations with a frequency of 0.4 Hz or higher. Conformance with the criterion may be demonstrated with the use of small signal eigenvalue analysis to explicitly identify the damping ratio of all questionable oscillations.

Time domain analysis may also be utilized to determine acceptable system damping. Acceptable damping with time domain analysis requires running a transient stability simulation for sufficient time (up to 30 seconds) such that only a single mode of oscillation remains. A 53% reduction in the magnitude of the oscillation must then be observed over four periods of the oscillation, measuring from the point where only a single mode of oscillation remains in the simulation.

As an alternate method, the time domain response of system state quantities such as generator rotor angle, voltage, and interface transfers can be transformed into the frequency domain where the damping ratio can be calculated.

A sufficient number of system state quantities including rotor angle, voltage, and interface transfers should be analyzed to ensure that adequate system damping is observed.

STATE OF RHODE ISLAND
AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION **DOCKET No. 4360**

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all parties of record in this proceeding in accordance with the requirements of Section 1.7 (d) of the Public Utilities Commission's Rules of Practice and Procedure.

Dated at Boston, Massachusetts this 19th day of December, 2012.

Erica P. Bigelow
Counsel

Of Counsel for
ISO New England, Inc.