RichMay

ATTORNEYS AND COUNSELORS AT LAW

Eric J. Krathwohl, Esq.
Direct Dial: (617) 556-3857
E-mail: ekrathwohl@richmaylaw.com

April 16, 2009

BY FEDERAL EXPRESS

Nicholas Ucci, Coordinator
Energy Facility Siting Board
89 Jefferson Boulevard
Warwick, RI 02888

Re: Docket No. SB-2008-2; Narragansett Electric Co. d/b/a National Grid
Rhode Island Reliability Project

Dear Mr. Ucci:

Further to discussion at Tuesday's scheduling conference, we file herewith an additional six (6) copies of the information request responses and the pre-filed direct testimony filed in Docket No. 4029 at the Public Utilities Commission on behalf of ISO-New England, Inc.

Please call me or Eric Krathwohl if there are any questions.

Sincerely,

Erica R. Bigelow

Enclosure

cc: Kevin Flynn, Esq. (via e-mail)

RICH MAY, A PROFESSIONAL CORPORATION
176 Federal Street, Boston, MA 02110-2223
617.556.3800 FAX 617.556.3889
www.richmaylaw.com

STATE OF RHODE ISLAND
AND PROVIDENCE PLANTATIONS

ENERGY FACILITY SITING BOARD **DOCKET No. SB-2008-2**

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 1.20(d) of the Energy Facility Siting Board's Rules of Practice and Procedure.

Dated at Boston, Massachusetts this 16th day of April, 2009

Erica P. Bigelow, Esq., Counsel

Of Counsel for
ISO New England, Inc.

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

The Narragansett Electric Company d/b/a	)	
National Grid (Rhode Island Reliability Project)	)	RIPUC Docket No. 4029

PREFILED TESTIMONY OF FRANK MEZZANOTTE

ON BEHALF OF ISO NEW ENGLAND INC.

March 13, 2009

Mr. Mezzanotte is a Manager of Area Transmission Planning at ISO New England Inc. with the responsibility for the Southern New England studies. His testimony describes the responsibilities of ISO New England, 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 Reliability Project as a solution to such reliability concerns.

TABLE OF CONTENTS

1. Introduction

Q1. Please state your name, position, and business address.

A1. I am Frank Mezzanotte, Manager – Area Transmission Planning at ISO New England Inc. (the "ISO"). My business address is ISO New England Inc., One Sullivan Road, Holyoke, Massachusetts 01040.

Q2. Please state your educational background and work experience.

A2. I have a Masters in Power Engineering & Engineering Management from the George Washington University. I began my career with the Long Island Lighting Company where I worked for nineteen years in various planning and engineering positions. After that, I served as the Manager of System Engineering & Planning at Northern Virginia Electric Cooperative.

I joined Transmission Planning at the ISO as a Lead Engineer in June, 2001, was promoted to Supervisor in 2004, and achieved the title of Manager in 2008. My main responsibility has been to lead, coordinate and review studies in the three southern New England states of Rhode Island, Massachusetts and Connecticut. I have been directly involved in the development of all of the Regional Transmission Expansion Plan and Regional System Plan reports since joining the ISO in 2001.

I am a licensed Professional Engineer in the states of Massachusetts, New York and Virginia.

Q3. Have you previously testified before the Rhode Island Public Utilities Commission?

A3. Yes. I testified in the Southern Rhode Island Transmission Project proceeding in Docket No. 3732.

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

Q4. What is the purpose of your testimony in this proceeding?

A4. In my testimony, I describe generally the ISO's mission and responsibilities. I also describe the ISO's planning criteria and how they relate to the Federal Energy Regulatory Commission ("FERC"), the North American Electric Reliability Corporation ("NERC") and the Northeast Power Coordinating Council, Inc. ("NPCC") standards and requirements for the Nation's bulk power transmission system. My testimony supports the need for the Rhode Island Reliability Project to address identified reliability concerns in Rhode Island.

Q5. Please summarize your testimony.

A5. Based on studies to date and applicable regional reliability standards, the ISO is concerned about the reliability of the existing electricity delivery system in Rhode Island. In an effort to evaluate the ability of the transmission system in southern New England to continue to perform reliably, a working group, consisting of planners from the ISO, National Grid and Northeast Utilities was formed. Under my direction and supervision, this working group undertook a comprehensive forward looking transmission planning study, known as the Southern New England Transmission Reliability analysis. This analysis is documented in the

Southern New England Transmission Reliability Report, Needs Assessment ("Needs Assessment")[1].

Transmission reliability and dependence on local generation are major concerns for the Rhode Island system. Section 3.3.2 of the Needs Assessment identifies critical weaknesses in Rhode Island where, without transmission improvements, the system may fail to provide reliable service.

After establishing the existence, nature and location of the reliability concerns, the working group identified possible transmission solutions and evaluated each solution. This step involved determining the advantages and disadvantages of each possible transmission solution: what new infrastructure, configurations and operational changes could best cure the identified problems. The working group detailed this analysis in the New England East-West Options Analysis ("Options Report")[2], including the selection of the Rhode Island Reliability Project (the "Project") in conjunction with the Interstate Reliability Project as the recommended solutions for the identified reliability concerns in Rhode Island.

The Project consists of a new 345 kV transmission line, and the relocation of two existing 115 kV transmission lines on an existing 21.4 mile right-of-way from the West Farnum Substation in North Smithfield to the Kent County Substation in Warwick. The major component of the Project is the construction of a second 345 kV transmission line to National Grid's existing Kent County Substation. In

[1] Included as Appendix D to the Petitioner's Environmental Report.
[2] Included as Appendix E to the Petitioner's Environmental Report.

order to accomplish this, it is necessary to relocate two existing 115 kV lines on the right-of-way and relocate short segments of other 115 kV lines. To accept the new 345 kV transmission line, the existing West Farnum and Kent County Substations will be expanded and modified.

In September 2008, Narragansett Electric Company ("National Grid") filed with the Rhode Island Energy Facility Siting Board an application to construct the Rhode Island Reliability Project. I support the Project as needed to address the reliability concerns identified in the Needs Assessment and to ensure the continuation of reliable electric service to customers in Rhode Island.

3. The ISO Mission and Responsibilities

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.[3] 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 bulk power system.

---

3 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).

The ISO was established to be the Independent System Operator of the New England bulk power grid on July 1, 1997,[4] and it assumed certain operating and transmission reservation responsibilities which had previously been carried out by NEPOOL, which transferred staff and assets to the ISO.

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.[5] 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 NEPOOL Market Participants. Its budget is reviewed and approved annually by FERC, and the ISO only recoups its annual expenses. As a result, market activity covers the ISO's expenses in monitoring and administering the system.

Q8. What are the ISO's mission and responsibilities?

A8. The ISO manages the New England region's bulk electric power system, operates the wholesale electricity market, administers the region's Open Access Transmission Tariff, and conducts regional transmission planning. More specifically, the ISO's responsibilities include independently operating and maintaining a highly reliable bulk transmission system, promoting efficient wholesale electricity markets, and working collaboratively and proactively with

---

4 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).

5 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).

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.[6] 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 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, causing the loss of approximately 2,500 megawatts ("MW") of load in New England, 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 bulk power transmission system. A well coordinated regional 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.

[6] 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).

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. The ISO annually prepares a comprehensive Regional System Plan ("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 throughout New England to maintain system reliability, improve the efficiency of system operations, increase system transfer capability, 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. Reliability Standards

Q10. What criteria does the ISO use in determining whether electricity service in New England, including Rhode Island, 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 to the distribution systems served by the Participating Transmission Owners. Without this objective, the probability of widespread electric outages to many customers is increased significantly. In other words, the reliability objectives seek to keep the lights on in the region, generally, and in specific areas of transmission need, particularly.

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 rules and criteria applicable to all geographic areas. NPCC has established a set of rules and criteria particular to the Northeast, although they also encompass the more general NERC standards. In turn, the ISO has developed standards and criteria specific to New England that coordinate with the NPCC rules. Similar standards 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 for it 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 Document A-2, "Basic Criteria for the Design and Operation of Interconnected Power Systems" (revised May 2004) attached as Attachment A. The ISO planning procedures are designed to meet the reliability standards that are specifically defined in Planning Procedure No. 3, "Reliability Standards for the New England Bulk Power Supply System" ("PP3"), attached as Attachment B. PP3 provides the published standard that 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. <u>The Reliability of the Transmission System in Rhode Island</u>

Q11. Does the ISO have concerns regarding the ability of the transmission system in Rhode Island to provide continued reliable electric service?

A11. Yes. The Needs Assessment identifies and details reliability concerns with the Rhode Island electric system. The ISO presented the deficiencies of the Rhode Island electric system at PAC meetings on five different occasions: May 4, 2005; March 15, 2006; December 15, 2006; December 3, 2007; and May 19, 2008.

Q12. What are the ISO's concerns regarding the ability of this transmission system to provide continued reliability of electricity service in Rhode Island?

A12. From a reliability perspective, the ISO is concerned that the existing system in Rhode Island faces a combination of growing summer peak demand, limited transmission capacity, and limited generation that is effectively integrated to serve the load. As the Needs Assessment shows, there is a high and increasing potential exposure to being unable to withstand single and multiple element contingencies following the single loss or outage of certain critical facilities in Rhode Island 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 and security standards established by NERC, the NPCC and the ISO.

Because of Rhode Island's dependence on local generation, reliability concerns are exacerbated if local generation is unavailable. If local generation is not available, the limited amount of electricity that the existing transmission system can import from other areas and transmit in Rhode Island places the area at an unacceptable risk of loss of service.

Q13. *What specifically are the ISO's reliability concerns in Rhode Island?*

A13. The ISO shares National Grid's concerns with thermal overloading of transmission lines, poor voltage performance and potential voltage collapse. As stated in the Needs Assessment, transmission system reliability and dependence on local generation are the major concerns for the Greater Rhode Island area. A number of steady-state thermal and voltage violations were observed on the transmission facilities while analyzing the conditions for the 2009 system.

The reliability problems on the Rhode Island 115 kV system are caused by a number of contributing factors (both independently and in combination), including high load growth (especially in southwestern Rhode Island and the coastal communities), generation unit availability, and transmission outages (planned or unplanned). Additionally, the Rhode Island 115 kV system is constrained when one of the Greater Rhode Island 345 kV lines is out-of-service. The 345 kV transmission lines critical for serving load in the Rhode Island 115 kV system are as follows:

- Line 328 (Sherman Rd – West Farnum)
- Line 332 (West Farnum – Kent County)
- Line 315 (West Farnum – Brayton Point)
- Line 303 (ANP Bellingham – Brayton Point)

Outage of any of these transmission lines result in limits to power transfer into Rhode Island. For line-out conditions, the next critical contingency would involve a loss of a 345/115 kV autotransformer or the loss of a second 345 kV tie.

Q14. How do thermal overloads occur?

A14. Thermal overloads occur when transmission lines, often as a result of a contingency event elsewhere in the system, carry current in excess of their design capacity. 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 that could affect areas well outside Rhode Island.

Transmission lines have normal and emergency current ratings. Normal ratings are the rating limits within which a line should generally operate 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 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. Lines that sagged into trees in Ohio contributed to the Northeast Blackout of August 2003.

Q15. Why is low voltage a concern?

A15. 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.

Q16. How many violations of the ISO Reliability Standards may occur before a system is considered to be out of compliance?

A16. None. A system that has only one violation of the criteria outlined in the ISO Reliability Standards is not in compliance.

Q17. What consequences can an uncontrolled blackout have?

A17. 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 in 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 more expensive.

6. **Benefits of the Rhode Island Reliability Project**

Q18. *What reliability benefits will the Rhode Island Reliability Project provide to the transmission system?*

A18. The installation of the Rhode Island Reliability Project will address the reliability issues described above by eliminating the thermal and voltage criteria violations. Moreover, the transmission upgrades will serve to ensure that Rhode Island's transmission system remains in compliance with NERC, the NPCC, and the ISO reliability standards.

Q19. *Are there any factors that could influence the timing of when these upgrades are needed?*

A19. Yes. The first Forward Capacity Auction ("FCA") was held in February 2008 and the second FCA was held in December 2008. The ISO's Tariff requires that the ISO "reflect proposed market responses in the regional system planning process."[7] As required by the Tariff, the ISO has considered the impact on the need for the Rhode Island Reliability Project based on the cleared resources resulting from the FCA. Additionally, the ISO has considered the timing of need for the project based on recent load forecasts.

The ISO has concluded that neither the FCA resources nor the revised load forecast would affect the timing of the need for the project. A total of 76 MW of

[7] Section 4.2(a) of Attachment K to the ISO New England Transmission, Markets and Services Tariff.

Demand Resources in Rhode Island cleared in the second FCA. Only about half of these resources are located in the load area that would impact the need for the project. Additionally, only two New Generating Capacity Resources in Rhode Island cleared in the auctions and both of these resources are small landfill units. Finally, the recent reduced load forecast is comparable (within 1%) of the original 2005 forecast in the Needs Assessment.

Q20. Will these findings be presented to the PAC?

A.20. Yes. The findings and analysis supporting the determination that neither the FCA resources nor the revised load forecast affect the timing of the need for the Rhode Island Reliability Project will be presented to the PAC on May 15, 2009.

Q21. Does the ISO support the proposed Rhode Island Reliability Project?

A21. Yes. As described above and in the Needs Assessment, the ISO is concerned about the ability of the existing transmission system to maintain reliable electric service in Rhode Island. The Rhode Island Reliability Project proposes a new 345 kV line from West Farnum to Kent County, which is needed to support the southwestern Rhode Island area if the existing 345 kV line (line 332) is lost, especially if either the FPLE Rhode Island State Energy generation plant or Manchester Street generation plant is out-of- service. The Project will provide a critical reinforcement when line 332 is out-of- service and an additional key southwestern Rhode Island element is lost (an N-1-1 contingency condition).

Q22. Does this conclude your testimony?

A22. Yes, thank you.

ISO ATTACHMENT LIST

Frank Mezzanotte

Attachment A	NPCC Document A-2 "Basic Criteria for the Design and Operation of the Interconnected Power Systems."
Attachment B	ISO Planning Procedure No. 3, "Reliability Standards for the New England Bulk Power Supply System."

Direct Testimony of Frank Mezzanotte

Attachment A

NPCC Document A-2

NORTHEAST POWER COORDINATING COUNCIL

1515 BROADWAY, NEW YORK, NY 10036-8901 TELEPHONE: (212) 840-1070 FAX: (212) 302-2782

Basic Criteria for Design and Operation Of Interconnected Power Systems

Adopted by the Members of the Northeast Power Coordinating Council September 20, 1967, based on recommendation by the Operating Procedure Coordinating Committee and the System Design Coordinating Committee, in accordance with paragraph IV, subheading (a), of NPCC's Memorandum of Agreement dated January 19, 1966 as amended to date.

Revised:	July 31, 1970
Revised:	June 6, 1975
Revised:	May 14, 1980
Revised:	March 2, 1984
Revised:	October 26, 1990
Revised:	August 9, 1995
Revised:	May 6, 2004

1.0 Introduction

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 5.1 and 5.2. 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 these criteria. 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**. (Terms in bold typeface are defined in the Glossary located in Document A-7, the *NPCC Glossary of Terms*).

Criteria described in this document are to be used in the design and operation of the **bulk power system.** These criteria meet or exceed the North American Electric Reliability Council (NERC) policies and standards. These criteria are applicable to all entities which are part of or make use of the **bulk power system**. The Council member whose system is used to connect a non-member system to the **bulk power system** shall assure that, whenever it enters into arrangements or contractual agreements with non-members whose system could have a **significant adverse impact** on service reliability on the interconnected **bulk power system** in Northeastern North America, the terms of such arrangements or contractual agreements are consistent with criteria established by the Council, NERC, or the Regional Reliability Councils established in areas in which the facilities used for such arrangements are located.

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/baseload/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.

It is the responsibility of each **Area** to ascertain that its portion of the **bulk power system** is designed and operated in conformance with these criteria. The Council provides a forum for coordinating the design and operations of its five **Areas**.

Through committees, task forces, and working groups the Council shall conduct regional and interregional studies, and assess and monitor **Area** studies and operations to assure conformance to the criteria.

2.0 General Requirements

Area, Member system or local conditions may require 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 the Basic Criteria are not necessarily applicable to those **elements** that are not a part of the **bulk power system** or in the portions of a member system where instability or overloads will not jeopardize the reliability of the remaining **bulk power system.**

2.1 Design Criteria

The design criteria will be used in the assessment of the **bulk power system** of each of the NPCC member systems and each NPCC **Area**, and in the reliability testing at the member system, **Area**, 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.

A **special protection system (SPS)** shall be used judiciously and when employed, shall be installed, consistent with good system design and operating policy.

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. An **SPS** may also be applied to preserve system integrity in the event of **severe facility outages** and extreme **contingencies.** The decision to employ an **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*, (Document A-5), and the *Special Protection System Criteria*, (Document A-11).

2.2 Operating Criteria

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

The operating criteria represent the application of the design criteria to inter-**Area**, intra-**Area** (inter-system) and intra-system operation.

The operating criteria define the minimum level of reliability that shall apply to inter-**Area** operation. Where inter-**Area** reliability is affected, each **Area** shall establish limits and operate so that the **contingencies** stated in Section 6.1 and 6.2 can be withstood without causing a **significant adverse impact** on other **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.

2.3 System Analysis and Modeling Data Exchange Requirements

It is the responsibility of NPCC, its **Areas** 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 operation and design. Also, any sharing of such information must not violate anti-trust laws.

For reliability purposes, **Areas** 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 member within an NPCC **Area** shall provide needed information to its **Area** representative 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.

Areas and member systems 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.

Areas shall install dynamic recording devices and provide recorded data necessary to enhance analysis of wide area system disturbances and validate system simulation models. These devices should be time synchronized and should have sufficient data storage to permit a few minutes of data to be collected. Information provided by these recordings would be used in tandem, when appropriate, with shorter time scale readings from fault recorders and sequence of events recorders (SER), as described in the *Bulk Power System Protection Criteria* (Document A-5), paragraph 2.7.2.

3.0 Resource Adequacy - Design Criteria

Each **Area's** probability (or risk) of disconnecting any **firm load** due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criteria 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 **Areas** and **Regions**, transmission transfer capabilities, and capacity and/or load relief from available operating procedures.

4.0 Resource Adequacy - Operating Criteria

Each **Area** 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 **Area**'s forecasted load and reserve requirements, in accordance with the NPCC *Operating Reserve Criteria* (Document A-6).

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 Area on a regular basis.

5.0 Transmission Design Criteria

The portion of the **bulk power system** in each **Area** and of each member system shall be designed with sufficient transmission capability to serve forecasted loads under the conditions noted in Sections 5.1 and 5.2. 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 **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 **Area** to another, as well as within **Areas**, shall be considered in the design of inter-**Area** and intra-**Area** transmission facilities. Transmission transfer capabilities shall be determined in accordance with the conditions noted in Sections 5.1 and 5.2.

5.1 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 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 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.

5.2 Steady State Assessment

a. Each **Area** shall design its system in accordance with these criteria and its own voltage control procedures and criteria, and coordinate these with adjacent **Areas** and **control areas.** Adequate reactive power resources and appropriate controls shall be installed in each **Area** to maintain voltages within normal limits for predisturbance conditions, and within **applicable emergency limits** for the system conditions that exist following the **contingencies** specified in 5.1.

b. Line and equipment loadings shall be within normal limits for predisturbance conditions and within **applicable emergency limits** for the system conditions that exist following the **contingencies** specified in 5.1.

5.3 Fault Current Assessment

Each **Area** 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 **Areas** and **Regions**.

6.0 Transmission Operating Criteria

Scheduled outages of facilities that affect inter-**Area** reliability shall be coordinated sufficiently in advance of the outage to permit the affected **Areas** to maintain reliability. Each **Area** shall notify adjacent **Areas** 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-**Area** reliability. Work on facilities which impact inter-**Area** reliability shall be expedited.

Individual **Areas** shall be operated in a manner such that the **contingencies** noted in Section 6.1 and 6.2 can be sustained and do not adversely affect other **Areas**.

Appropriate adjustments shall be made to **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**.

6.1 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 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.

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

Line and equipment loadings shall be within normal limits for predisturbance 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 **Areas** 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 **Areas** will not be subjected to the higher flows without prior agreement.

6.2 Emergency Transfers

When **firm load** cannot be supplied within normal limits in an **Area**, or a portion of an **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**.

6.3 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 6.2 above.

6.4 Operation Under High Risk Conditions

Operating to the **contingencies** listed in Sections 6.1 and 6.2 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 an **Area**, consideration should be given to operating in a more conservative manner than that required by the provisions of Sections 6.1 and 6.2.

7.0 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 5.1. 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 widespread **bulk power system** shutdown. It is the responsibility of each **Area** to identify additional extreme contingencies, if any, to be assessed.

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

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 5.1.

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 must be conducted, and measures may be utilized where appropriate to reduce the likelihood of such contingencies or to mitigate the consequences indicated in the assessment of such contingencies.

8.0 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 adverse system response. Each **Area** has the responsibility to incorporate special simulation testing to assess the impact of extreme system conditions.

For example, 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.

Lead Task Force:	Task Force on Coordination of Planning
Reviewed for concurrence by:	TFCO, TFSP, TFSS and TFIST Chairman
Review frequency:	4 years
References:	*Bulk Power System Protection Criteria* (Document A-5)
	Operating Reserve Criteria (Document A-6)
	NPCC Glossary of Terms (Document A-7)
	Special Protection System Criteria (Document A-11)

Direct Testimony of Frank Mezzanotte

Attachment B

ISO NEW ENGLAND PLANNING PROCEDURE NO. 3

RELIABILITY STANDARDS FOR THE NEW ENGLAND AREA BULK POWER SUPPLY SYSTEM

EFFECTIVE DATE: October 13, 2006

REFERENCES:

NERC Version 0 Reliability Standards

NPCC Document A-2, Basic Criteria for Design and Operation of Interconnected Power Systems, Revised May 6, 2004

NPCC Document A-3, Emergency Operation Criteria, Revised August 31, 2004

NPCC Document A-5, Bulk Power System Protection Criteria, Revised January 30, 2006

NPCC Document A-7, Glossary of Terms, Revised February 6, 2006

NPCC Document A-11, Special Protection System Criteria, Adopted November 14, 2002

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

Damping Criterion Basis Document, Stability Task Force, Approved July 12, 2006.

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 Generation, Dispatchable and Interruptible Loads
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 or voltage collapse. The loss of small portions of the system may be tolerated provided the reliability of the overall interconnected system is not jeopardized.

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 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**. 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
Rev. 3 Rec.: RC – 8/29/06; Rec.:PC – 10/13/06; Eff. 10/13/06

[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, 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. **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.

12. **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.

13. **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.

14. **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.

15. **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.

16. **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 0.2 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.