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He started his career with the former Long Island Lighting Company (LILCO) in New York where he held a variety of positions over a span of twenty-two years. His experience there included work in the following areas: Inter- and Intra-system Transmission Studies, Economic & System Analysis, Special Studies, Distribution Planning, and Substation Engineering.

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ISO Exhibit 2

NPCC Document A-2

NORTHEAST POWER COORDINATING COUNCIL

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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)

ISO NEW ENGLAND PLANNING PROCEDURE NO. 3

RELIABILITY STANDARDS FOR THE NEW ENGLAND AREA BULK POWER SUPPLY SYSTEM

EFFECTIVE DATE: June 11, 2009

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 April 1, 2009.

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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
Rev. 4 Rec.: RC – 5/19/09; Rec.:PC – 6/05/09; Eff. 6/11/09

[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 0.4 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.