NPCC Directory Mapping Document

The NPCC Directory project has been consolidating NPCC Criteria, Guidelines, and Procedures into one document while providing a consistent and comprehensive set of reliability requirements for the Northeast.

The enclosed mapping document is organized in a manner that provides an understanding of ‘what went where’ during the Directory development and translation process. The document provides a tracking of content language from the translated A, B and C documents.
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

Moved to Section 5.3 of Directory #1.

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

Moved to Section 5.4 of Directory #1.

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

Moved to Section 5.4.1 of Directory #1.

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.
<table>
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<tr>
<th>Lead Task Force:</th>
<th>Task Force on Coordination of Planning</th>
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<tr>
<td>Reviewed for concurrence by:</td>
<td>TFCO, TFSP, TFSS and TFIST Chairman</td>
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Not mapped since references to related documents are not needed when they are all mapped to the same
Draft A-03

Deletion of Restoration Language

Emergency Operation

Criteria

Mapping of A3 Conversion to Directory #2 – Emergency Operations

Adopted by the Members of the Northeast Power Coordinating Council January 25, 1982, 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: March 8, 1985
Revised: July 3, 1989
Reviewed: October 10, 1990
Revised: August 6, 1993
Revised: October 1997
Revised: January 1999
Revised: November 1, 2002
Revised: August 31, 2004
Revised: mm dd, yyyy
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Figure 1-Standards for setting underfrequency trip protection for generators
1.0 Introduction

The purpose of these criteria is to present the basic factors to be considered in formulating plans and procedures to be followed in an emergency or during conditions which could lead to an emergency, in order to facilitate mutual assistance and coordination within NPCC. Objectives, principles and requirements are presented to assist the Area formulating plans and procedures to achieve desired results.

The definitions of terms in bold typeface can be found in the NPCC Reference Manual Document A-7, NPCC Glossary of Terms.

2.0 Objectives

The seven basic objectives in formulating plans related to emergency operating conditions are:

2.1 To avoid, to the extent possible, the interruption of service to firm load.

2.2 To minimize the occurrence of system disturbances.

2.3 To contain any system disturbance and limit its effects to the Area initially affected.

2.4 To minimize the effects of any system disturbances on customers.

2.5 To avoid damage to system elements.

2.6 To avoid hazard to the public by maintaining safe transmission line conductor clearances.

2.7 To be prepared for system restoration following a system disturbance.

3.0 Principles

Principles of operation, based on the foregoing objectives, are as follows:

3.1 Bulk power system facilities must not be removed from service without notification and coordination with adjacent Areas, except in an emergency, time does not permit such coordination, or when immediate action is required to prevent hazard to the public, sustained customer service interruption, or damage to facilities. In such cases adjacent Areas shall be informed as soon as possible.

3.2 Each Area shall maintain total net interchange schedules. Each Area exchange schedules as needed to maintain reliability.
3.3 Normal transfer capabilities shall be observed unless there is insufficient capacity or voltage support in an Area, in which case emergency transfer capabilities may be used prior to shedding firm load. Emergency transfer capabilities shall not be exceeded.

3.4 Each Area shall maintain automatic generation control equipment operational and in service except as stipulated in Section 4.5.

3.5 Operations during an emergency must recognize the requirements to balance load and generation, including support of system frequency, as well as the requirement to maintain system security, including thermal, voltage and stability limitations.

3.6 A trending of voltage through normal maximum or minimum values is an indication of insufficient real or reactive control in an Area. The affected Area must quickly restore the real and reactive power balance between load and source.

3.7 If an emergency is being caused in whole or in part by parallel power flows, the Area or Areas contributing to parallel power flows shall take all steps, including the shedding of firm load, to eliminate the parallel power flow contribution to the emergency, and the Area experiencing the emergency shall implement all steps, up to and including the shedding of firm load, in accordance with local or interconnection-wide transmission loading relief procedures.

3.8 When an affected Area within NPCC is unable to correct a situation, a request for assistance from an Area or systems outside NPCC shall be made. Upon receiving a request for assistance to mitigate an emergency, an Area shall provide maximum reasonable assistance to any other Areas or systems outside of NPCC and shall act within the time frame that such assistance is required (Note: Neighboring Areas will ensure suitable arrangements with the generating resources and / or transmission provider(s) in the Area are in place to be able to provide reasonable assistance.)

3.9 Reasonable assistance shall be requested only after comparable action(s) has been implemented by the requesting Area(s). Reasonable assistance shall normally consist of, in no implied order of priority:

3.9.1 Redispatching generation (may be subject to agreements).

3.9.2 Curtailing non-firm energy transfers to non-affected Areas

3.9.3 Arming special protection systems.
3.9.4 Purchasing capacity and energy on behalf of the Area experiencing the emergency.

3.9.5 Redistribution or sharing of operating reserve.

3.9.6 Shedding interruptible load where permitted by a power system's internal policy.

3.9.7 Implementing voltage reduction.

3.9.8 Loading facilities to their emergency transfer capabilities provided that adverse weather conditions do not prevent such assistance.

Reasonable assistance shall not normally require the shedding of firm load.

4.0 Requirements

In order to effectively adhere to the foregoing principles, each Area shall meet the following requirements:

4.1 Authority

Reliability Coordinators, Balancing Authority operators, and Transmission Operators shall have the responsibility and authority to implement emergency procedures including the curtailment of transactions and / or shedding of firm load.

4.2 Metering & Indication

Accurate and reliable metering and indication of system frequency, breaker status, voltage levels and power flows (real and reactive for all tie lines and other critical elements) shall be available to the appropriate system operator(s).

4.3 Communication

Reliable inter-Area and intra-Area voice communications shall be available to the Reliability Coordinators, Balancing Authority operators, and Transmission Operators, as appropriate to their accountabilities, with level of reliability at least equivalent to that provided by a dedicated and redundant circuit.
4.4 Operating Limits

A comprehensive set of operating limits for inter-Area and critical intra-Area interfaces, recognizing both normal and emergency transfer capabilities, shall be available to Reliability Coordinators, Balancing Authority operators and Transmission Operators as appropriate to their accountabilities. The circumstances under which each of these transfer capabilities may be used shall be clearly indicated by written instructions.

For operation with facilities out of service, the comprehensive set of operating limits shall be supplemented by revised sets for planned outage conditions, by judgment of the Reliability Coordinators, Balancing Authority operators and / or Transmission Operators, and by other studies as required.

4.5 Disabling Automatic Generation Controls

A sustained frequency excursion of ±0.2 Hertz is an indication of a major load-generation unbalance and possible formation of an island. It is important for the affected Area to reestablish a load-generation balance quickly, to restore frequency, and to allow islands to resynchronize as soon as possible. All automatic generation controls shall be removed from service at 59.8 Hertz on frequency decline and 60.2 Hertz on frequency increase.

4.6 Automatic Underfrequency Load Shedding

The intent of the Automatic Underfrequency Load Shedding program is to stabilize the system frequency in an Area during an event leading to declining frequency while recognizing the generation characteristics in each Area. The goal of the program is to arrest the system frequency decline and to return the frequency to at least 58.5 Hertz in ten seconds or less and to at least 59.5 Hertz in thirty seconds or less, for a generation deficiency of up to 25% of the load.

The Task Force on System Studies shall conduct a triennial study to coordinate the Automatic Underfrequency Load Shedding Program among the NPCC Areas. Each Area shall carry out the following unless an alternative plan is submitted by an Area for review by the NPCC Task Forces on Coordination of Operation and System Studies and approved by the NPCC Reliability Coordinating Committee:

4.6.1 Automatic load shedding of ten percent of its load at a nominal set point of 59.3 Hertz.

4.6.2 Automatic load shedding of an additional fifteen percent of its load at a nominal set point of 58.8 Hertz.
4.6.3 Underfrequency threshold relays shall be set to a nominal operating time of 0.30 second, from the time when frequency passes through the set point to the time of circuit breaker trip initiation (including any communications time delay), when the rate of frequency decay is 0.2 Hertz per second.

Studies shall be performed by each Area to ensure satisfactory voltage and loading conditions after automatic load shedding.

4.7 Under-voltage

Automatic under-voltage load shedding of selected loads to enhance power system security is permitted by an Area.

4.8 Manual Load Shedding

Each Area shall be capable of manually shedding at least fifty percent of its load in ten minutes or less. Manual load shedding plans shall not interrupt bulk power system elements.

Each Area shall carry out the following unless an alternative plan is submitted by an Area for review by the NPCC Task Forces on Coordination of Operation and System Studies and approved by the NPCC Reliability Coordinating Committee:

- The first half of the load shed manually shall not include load which is part of any automatic load shedding plan unless following this load shedding, the requirements of section 4.6 can still be met. (see Section 4.6).
- The plan shall include the capability of shedding load proportionately over the whole system, unless operating requirements limit load shedding to one part of a system.

Manual load shedding capability in excess of the minimum fifty percent is permitted by an Area.

Manual load shedding procedures shall be reviewed at least annually by member companies, to ensure that the proper amount of load can be shed within the time limits prescribed.

Studies shall be performed by each Area to ensure that satisfactory voltage and loading conditions prevail after manual load shedding.

4.9 Generator Underfrequency Tripping

Generators should not be tripped for under-frequency conditions in the area above the curve in Figure 1.
It is recognized that, in special cases, requirements may dictate generator trip in the region above the curve. In those cases, automatic load shedding additional to the amount set out in Section 4.6, equivalent to the amount of generation to be tripped, must be provided. Such cases shall be reviewed by the Task Force on Coordination of Operation.

The intent of the added compensating load shedding is to preserve the stability of an island, if formed, and to avoid major underfrequency load shedding by the Area, if it can be avoided. This can only be accomplished through a one to one correspondence of the generation lost and the immediate rejection of an equivalent neighboring load, at the frequency at which the given generator is tripped.

If the frequency decays below the curve shown in Figure 1, steps may be taken to protect generating equipment, including separation from the system with or without load. In such cases isolation onto a generator's own auxiliaries is preferred to facilitate rapid resynchronization as soon as system conditions permit. For time periods exceeding 300 seconds, actions such as those described in Sections 4.5 and 4.8 apply.

Existing exempt generators that trip above the curve in Figure 1 shall not increase their underfrequency trip settings or make other modifications that may cause their generator to, directly or indirectly, trip at a higher frequency.

### 5.0 Operation During Abnormal Conditions

5.1 When an Area foresees, or is experiencing, abnormal operating conditions, appropriate measures, as stated in the NPCC Procedures During Abnormal Operating Conditions, shall be implemented.

5.2 Appropriate measures shall be taken to maximize the availability of equipment critical to the security and restoration of the bulk power system.

### 6.0 Responsibilities

All Reliability Coordinators, Control Area operators, facilities owners/ operators and system operators are responsible for observing these criteria.

The monitoring of automatic underfrequency load shedding requirements (Section 4.6), the monitoring of manual load shedding requirements (Section 4.8) and the monitoring of the requirements of underfrequency generator.
(Section 4.9) will be carried out by the NPCC Compliance Monitoring and Assessment Subcommittee.

Lead Task Force: NPCC Task Force on Coordination of Operation

Review frequency: 3 Years

References:
- NPCC Procedures During Abnormal Operating Conditions (NPCC Document C-20)
- NPCC Glossary of Terms (NPCC Document A-07)
- NERC Version 0 Reliability Standards

Removed since references are no longer needed when all relevant materials are incorporated into Directory #2.
Figure 1 - Standards for setting underfrequency trip protection for generators

Generator tripping permitted on or below curve without requiring additional equivalent automatic load shedding.
DRAFT -Clean
January 23, 2008
Maintenance Criteria for
Bulk Power System Protection

This draft criteria document, in its entirety, has been mapped to Directory 3 - Maintenance Criteria for Bulk Power System Protection.

Adopted by the Members of the Northeast Power Coordinating Council April 22, 1969, based on recommendations by 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 13, 1971
Revised: May 18, 1979
Revised: August 2, 1982
Revised: April 21, 1986
Revised: August 19, 1991
Revised: November 8, 1995
Revised: March 1997
Revised: September 1998
Revised: December 2000
Revised: August 30, 2004
Note:

Terms in bold typeface are defined in the *NPCC Glossary of Terms* (Document A-7)
1.0 Introduction

This document establishes NPCC’s minimum protection maintenance criteria.

1.1 Applicability

These criteria shall apply to all protection of the NPCC bulk power system, including Type I special protection systems and protection required for the NPCC Automatic Underfrequency Load Shedding Program.

Automatic underfrequency load shedding protection systems and generator underfrequency tripping relays are not generally located at bulk power system stations; however, they have a direct effect on the operation of the bulk power system during major emergencies, and as such, they are subject to this Criteria.

2.0 General

Minimum periodic testing of each protection group shall be conducted to verify that the protection group is capable of performing its intended protection function. Such testing shall include protection assembly testing (as illustrated in attached Figure 1) and protection group system testing. To assure satisfactory operation of the protective equipment as a system, test procedures and test facilities must ensure that related tests properly overlap.

3.0 Protection Assembly Testing

Refer to Figure 1, equipment marked as [1]

The following Protection Assembly testing shall be performed on an interval not exceeding that specified in Table 1 for bulk power system protection groups:

- making visual inspections,
- verifying inputs and outputs,
- confirming that the intended version of software is installed (microprocessor-based relays),
- verifying correct protection operation,
- verifying the integrity of current and voltage transformers and associated circuitry. This verifies that the correct secondary quantities are input to the relay. For microprocessor relays, verify the internal analog inputs with an independent source.
TABLE 1
INTERVALS FOR PROTECTION ASSEMBLY TESTING

<table>
<thead>
<tr>
<th>Note (1)</th>
<th>Note (2)</th>
<th>Note (3)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Non-Self Monitored Protection Assembly</td>
<td>Microprocessor-Based Protection Assembly</td>
<td>Microprocessor-Based Protection Assembly</td>
</tr>
<tr>
<td>4 years</td>
<td>6 years</td>
<td>8 years</td>
</tr>
</tbody>
</table>

Notes:

(1) Non-Self Monitored protection assemblies includes electromechanical relays and solid state relays.

(2) Microprocessor-based protection assemblies where the principal fault-sensing and logic components include self monitoring or self checking, and the failure alarm is monitored to an Operator.

(3) Microprocessor-based protection assemblies as per Note (2), plus additional self monitoring or self checking of ac voltage and current input integrity, and the failure alarm is monitored to an Operator.

4.0 Protection Group DC Circuit Tests

Refer to Figure 1, equipment marked as [2]

Tests performed in Section 3.0 above, verify the operation of the ac signaling-measuring relays, and verify a protection assemblies’ ability to initiate a trip output(s). However, to verify operation of the protection group as a system, DC circuit testing is required. These tests verify the protection equipment operation from the trip outputs of the protection assembly up to breaker trip coils. DC circuit testing can be achieved by verifying overlapping protection group equipment zones, normally bound by test switches, or by test tripping the protection group.

DC circuit test tripping shall be performed on an interval not exceeding that specified in Table 2 for bulk power system protection groups:
### TABLE 2
INTERVALS FOR DC CIRCUIT TEST TRIPPING

<table>
<thead>
<tr>
<th></th>
<th>Non-Monitored</th>
<th>Monitored</th>
<th>Note (1)</th>
</tr>
</thead>
<tbody>
<tr>
<td>DC Circuit Tripping</td>
<td>4 years</td>
<td>6 years</td>
<td></td>
</tr>
</tbody>
</table>

Note (1): Trip coil and DC circuit continuity is continuously monitored to an Operator.

### 5.0 Battery Banks and Chargers

Refer to Figure 1, equipment marked as [5]

Voltage verification of the station battery(s) shall be performed on an interval not exceeding that specified in Table 3 for bulk power system protection groups:

### TABLE 3
BATTERY BANKS AND CHARGER TESTING

<table>
<thead>
<tr>
<th></th>
<th>Non-Monitored</th>
<th>Monitored</th>
<th>Note (1)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Battery Voltage</td>
<td>Every month</td>
<td>Continuous</td>
<td></td>
</tr>
</tbody>
</table>

Note (1): Battery Voltage is continuously monitored to an Operator.

### 6.0 Breaker Test tripping

Refer to Figure 1, equipment marked as [4]

The ability of the breaker(s) to trip via each trip coil shall be verified every two years. Nuclear plants with refuel cycles longer than two years can complete these tests at an interval not to exceed three years.

### 7.0 Telecommunications

Refer to Figure 1, equipment marked as [3a] and [3b]

#### 7.1 Terminal Equipment
Telecommunications terminal equipment shall be tested on the same time interval as the protection assemblies as per Table 1 above.

7.2 Channel Health

For trip equipment which uses frequency shift keying (FSK) mode of communication, such as Power Line Carrier systems, the ability to perform its intended trip function shall be verified every twelve months. This testing is not required for telecommunication systems that continuously verify this functionality to an Operator – alarmed and monitored.

The signal adequacy shall be tested every month and the ability of a channel to perform its intended function shall be verified every twelve months on telecommunication systems that are not continuously monitored. An example of such a system is on/off Power Line Carrier.

8.0 Underfrequency Load Shedding and Generator Tripping

Protection group DC circuit tests for protection required by the NPCC Automatic Underfrequency Load Shedding Program need not be performed more frequently than the protection group DC circuit tests for other protection on the same breaker. Because of the distributed nature of this load shedding protection, random failures to trip do not compromise the objectives of the NPCC Automatic Underfrequency Load Shedding Program.

The successful operation of the NPCC Automatic Load Shedding Program requires the proper coordination of generator underfrequency tripping, as described in the NPCC Emergency Operation Criteria, Document A-3. For generators rated 20 MW and above, the correct calibration of generator underfrequency tripping relays shall be verified at an interval not exceeding that specified in Table 1.

9.0 Maintenance Reporting

Adherence to this Criteria must be reported in a manner and form designated by the Compliance Committee. Exceptions to Document A-4 requirements are acceptable if the exceptions are completely removed within five (5) months of the end of the calendar year in which the testing is due. The intervals specified in this document refer to calendar year in which testing is due regardless of the date.
Lead Task Force: Task Force on System Protection

Review frequency: 3 years

References:
- NPCC Glossary of Terms (Document A-7)
- NPCC Guide for Maintenance of Microprocessor-based Protection Relays (Document B-23)

References not mapped to Directory #3 since all relevant materials are now incorporated into Directory #3.
FIGURE 1

HV Transmission Line

Switchyard

CT
CB
DS
PT
[4] To Breaker Trip Coil

CT
CB
DS
PT
[4] To Breaker Trip Coil

Protection Assembly

[2] Protective Relays (Measuring)

[3a] Aux Relays

Telecomm. Rack

Bidirectional Signals

[3b] Telecomm. Rack

Bidirectional Signals

[3a] Aux Relays

Protection Assembly

[2] Protective Relays (Measuring)

[3a] Aux Relays

[3b] Telecomm. Rack

Station 'A'

Relay and Control House

Battery System

[5] Battery System

Station 'B'

Only One Protection Group Shown Per Station

LEGEND:
CB Circuit Breaker
CT Instrument Transformer (Current Transformer)
PT Instrument Transformer (Potential Transformer)
DS Disconnect Switch
MO Motor Operated
← Wire & Cable

JLC
Draft December 4, 2008
Bulk Power System
Protection Criteria

Adopted by the Members of the Northeast Power Coordinating Council Inc., this May 21, 2007, based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Inc. Bylaws dated May 18, 2006 as amended to date.

Revised: February 29, 1980
Revised: May 9, 1983
Revised: February 2, 1987
Revised: June 9, 1989
Revised: October 26, 1990
Revised: August 9, 1995
Revised: September 1998
Revised: November 14, 2002
Revised: January 30, 2006
Revised: May 21, 2007
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Note:

Terms in bold typeface are defined in the *NPCC Glossary of Terms* (Document A-7)
1.0 Introduction

This document establishes the **protection** criteria, for **protection** of the NPCC **bulk power system**. It is not a design specification. It is recognized that certain Areas or member systems may choose to apply more rigid criteria because of local considerations. Guidance for consideration in the implementation of these criteria is provided in Document B-5.

Compliance with these criteria will be reviewed by TFSP in accordance with NPCC Procedure for Reporting and Reviewing Proposed Protection Systems for the Bulk Power System (Document C-22).

1.1 Applicability

1.1.1 New Facilities

These criteria shall apply to all new Bulk Power System facilities.

1.1.2 Existing Facilities

It is the responsibility of individual companies to assess the **protection systems** at existing facilities and to make modifications which are required to meet the intent of these criteria as follows:

1.1.2.1 Planned Renewal or Upgrade to Existing BPS Facilities

It is recognized that there may be portions of the bulk power system, which existed prior to each member’s adoption of the Bulk Power System Protection Criteria (Document A-5) that do not meet these criteria. If any protection systems or sub-systems of these facilities are replaced as part of a planned renewal or upgrade to the facility and do not meet all of these criteria, then an assessment shall be conducted for those criteria that are not met. The result of this assessment shall be reported on the appropriate portion of the C22 forms, for consideration by the TFSP.

1.1.2.2 Facility Classification Upgraded to Bulk Power System

These criteria apply to all existing facilities which become classified as bulk power system. A
mitigation plan shall be required to bring such a facility into compliance with these criteria. Where the owner of the protection system has determined that the cost and risks involved to implement a mitigation plan that achieves complete physical cable/wiring separation in accordance with Section 3.10.2 is not justified, such assessment shall be reported on the appropriate portion of the C-22 forms, for consideration by the TESP.

1.1.2.3 Additions to Bulk Power System Facilities

If a bulk power system element is added to an existing bulk power system facility that is recognized under section 1.1.2.1, Planned Renewal or Upgrade to Existing Facilities, these criteria apply to the protection systems for the new element.

1.1.2.4 “In-kind” Replacement of Bulk Power System Equipment

If a bulk power system element (e.g., breaker, transformer, capacitor bank, reactor, etc.) or a protective relay is replaced “in-kind” as a result of an unplanned event, then it is not required to upgrade the associated protection system to comply with these criteria.

1.1.2.5 Change in Bulk Power System Facility Status

Where a facility was originally on the BPS list of April 2007 and has been shown to be non-BPS but later was determined to be BPS again, Section 1.1.2.1 would apply. When the facility returns to BPS status, it must be maintained in accordance with Directory #3 within two years timeframe.

1.2 Responsibility

Whenever changes are anticipated in generating sources, transmission facilities, or operating conditions, members shall review those protection system applications (i.e., settings, ac and dc supplies) which can reasonably be expected to be impacted by those changes.

Mapped to Section 1.6.3 of Directory 4.
2.0 General Criteria

Due consideration shall be given to dependability and security. For those protective relays intended for removal of faults from the bulk power system, dependability is paramount, and the redundancy provisions of the criteria shall apply. For Protective relays installed for reasons other than fault sensing such as overload, etc., security is paramount, and the redundancy provisions of the criteria do not apply. The relative effect on the bulk power system of a failure of a protection system to operate when desired versus an unintended operation shall be weighed carefully in selecting design parameters as follows:

2.1 Issues Affecting Dependability

2.1.1 Except as identified otherwise in these criteria, all elements of the bulk power system shall be protected by two protection groups, each of which is independently capable of performing the specified protective function for that element. This requirement also applies during energization of the element.

2.1.2 Except as identified otherwise in these criteria, the two protection groups shall not share the same component.

2.1.3 Means shall be provided to trip all necessary local and remote breakers in the event that a breaker fails to clear a fault. This protection need not be duplicated.

2.2 Issues Affecting Security

2.2.1 Protection systems shall be designed to isolate only the faulted element, except in those circumstances where additional elements are tripped intentionally to preserve system integrity, or where isolating additional elements has no impact outside the local area.

2.3 Issues Affecting Dependability and Security

2.3.1 The thermal capability of all protection system components shall be adequate to withstand rated maximum short time and continuous loading of the associated protected elements.
2.3.2 Communication link availability, critical switch positions, and trip circuit integrity, shall be monitored to allow prompt attention by appropriate operating authorities.

2.3.3 When remote access to protection systems is possible, the design shall include security measures to minimize the probability of unauthorized access to the protection systems.

2.3.4 Short Circuit Models used to assess protection scheme design and to develop protection settings shall take into account minimum and maximum fault levels and mutual effects of parallel transmission lines. Details of neighboring systems shall be modeled wherever they can affect results significantly.

2.4 Operating Time

**Bulk power system protection** shall take corrective action within times determined by studies with due regard to security, dependability and selectivity.

2.5 This section is intentionally left blank.

2.6 **Protection System Testing and Maintenance**

2.6.1 Protection systems shall be maintained in accordance with the **Maintenance Criteria for Bulk Power System Protection** (Document A-4Directory #3).

2.6.2 The design of protection systems both in terms of circuitry and physical arrangement shall facilitate periodic testing and maintenance.

2.6.3 Each protection group shall be functionally tested to verify the dependability and security aspects of the design, when initially placed in service and when modifications are made.

2.7 Analysis of Protection Performance

2.7.1 Bulk power system automatic operations shall be analyzed to determine proper protection system performance. Corrective measures shall be taken promptly if a protection group fails to operate or operates incorrectly.
2.7.2 Event and fault recording capability shall be provided to permit analysis of system disturbances and protection system performance.

2.7.3 Internal clocks in event and fault recording equipment shall be time synchronized to within 2 milliseconds or less of Universal Coordinated Time scale. The time zone shall be clearly identified as either universal time zone or local time zone.

2.7.4 Each protective relay which trips Bulk Power System equipment shall provide separate target indication.

3.0 Equipment and Design Considerations

3.1 Current Transformers

Current transformers (CTs) associated with protection systems shall have adequate steady-state and transient characteristics for their intended function as follows:

3.1.1 The output of each current transformer secondary winding shall be designed to remain within acceptable limits for the connected burdens under all anticipated fault currents to ensure correct operation of the protection system.

3.1.2 The thermal and mechanical capabilities of the CT at the operating tap shall be adequate to prevent damage under maximum fault conditions and normal or emergency system loading conditions.

3.1.3 For protection groups to be independent, they shall be supplied from separate current transformer secondary windings.

3.1.4 Interconnected current transformer secondary wiring shall be grounded at only one point.

3.1.5 Current transformers shall be connected so that adjacent protection zones overlap.

3.2 Voltage Transformers and Potential Devices

Voltage transformers and potential devices associated with protection systems shall have adequate steady-state and transient characteristics for their intended functions as follows:

Section 3.1 mapped to Section 5.6 of Directory 4.

Section 3.2 mapped to Section 5.7 of Directory 4.
3.2.1 Voltage transformers and potential devices shall have adequate volt-ampere capacity to supply the connected burden while maintaining their relay accuracy over their specified primary voltage range.

3.2.2 The two protection groups protecting an element shall be supplied from separate voltage sources. The two protection groups may be supplied from separate secondary windings on one transformer or potential device, provided all of the following requirements are met:

- Complete loss of one or more phase voltages does not prevent all tripping of the protected element;
- Each secondary winding has sufficient capacity to permit fuse protection of the circuit;
- Each secondary winding circuit is adequately fuse protected.

3.2.3 The wiring from each voltage transformer secondary winding shall not be grounded at more than one point.

3.3 This section is intentionally left blank.

3.4 This section is intentionally left blank.

3.5 Batteries and Direct Current (dc) Supply

DC supplies associated with protection shall be designed to have a high degree of dependability as follows:

3.5.1 No single battery or dc power supply failure shall prevent both independent protection groups from performing the intended function. Each battery shall be provided with its own charger. Physical separation shall be maintained between the two station batteries or dc power supplies used to supply the independent protection groups.

3.5.2 Each station battery shall have sufficient capacity to permit operation of the station, in the event of a loss of its battery charger or the ac supply source, for the period of time necessary to transfer the load to the other station battery or re-establish the supply source. Each station battery and its associated charger shall have sufficient capacity to supply the total dc load of the station.
3.5.3 A transfer arrangement shall be provided to permit connecting the total load to either station battery without creating areas where, prior to failure of either a station battery or a charger, a single event can disable both dc supplies.

3.5.4 The battery chargers and all dc circuits shall be protected against short circuits. All protective devices shall be coordinated to minimize the number of dc circuits interrupted.

3.5.5 Dc systems shall be continuously monitored to detect abnormal voltage levels (both high and low), dc grounds, and loss of ac to the battery chargers, in order to allow prompt attention by the appropriate operating authorities.

3.5.6 Protection groups dc sources shall be continuously monitored to detect loss of voltage in order to allow prompt attention by the appropriate operating authorities.

3.6 Station Service ac Supply

On bulk power system facilities, there shall be two sources of station service ac supply, each capable of carrying at least all the critical loads associated with protection systems.

3.7 Circuit Breakers

No single trip coil failure shall prevent both independent protection groups from performing the intended function. The design of a breaker with two trip coils shall be such that the breaker will operate if both trip coils are energized simultaneously. The correct operation of this design shall be verified by tests.

3.8 Teleprotection

Communication facilities required for teleprotection shall be designed to have a level of performance consistent with that required of the protection system, and shall meet the following:

3.8.1 Where each of the two protection groups protecting the same bulk power system element requires a communication channel,
the equipment and channel for each protection group shall be separated physically and designed to minimize the risk of both protection groups being disabled simultaneously by a single event or condition.

3.8.2 Teleprotection equipment shall be monitored to detect loss of equipment and/or channel to allow prompt attention by the appropriate operating authorities.

3.8.3 Teleprotection systems shall be provided with means to test for proper signal adequacy.

3.8.4 Teleprotection equipment shall be powered by the substation batteries or other sources independent from the power system.

3.8.5 Except as identified otherwise in these criteria, the two teleprotection groups shall not share the same component.

3.8.5.1 The use of a single communication tower for the radio communication systems used by the two protection groups protecting a single element, is permitted as long as directional diversity of the communication signals is achieved.

3.9 This section is intentionally left blank.

3.10 Environment

3.10.1 Each separate protection group and Teleprotection protecting the same system element shall be on different non-adjacent vertical mounting assemblies or enclosures.

3.10.2 In the event a common raceway is used, cabling for separate protection groups protecting the same system element shall be separated by a fire barrier.

3.11 Grounding

Station grounding is critical to the correct operation of protection systems. The design of the ground grid directly impacts proper protection system operation and the probability of false operation from fault currents or transient voltages.
3.11.1 Each member shall have established as part of its substation design procedures or specifications, a mandatory method of designing the substation ground grid, which:

- Can be traced to a recognized calculation methodology
- Considers cable shielding
- Considers equipment grounding

4.0 Specific Application Considerations

4.1 Transmission Line Protection

4.1.1 Protection system settings shall not constitute a loading limitation as per NERC requirement/standard. In cases where NERC approved exceptions are used the limits thus imposed shall be adhered to as system operating constraints.

4.1.2 A pilot protection shall be so designed that its failure or misoperation will not affect the operation of any other pilot protection on that same element.

4.2 This section is intentionally left blank.

4.3 Breaker Failure Protection

Means shall be provided to trip all necessary local and remote breakers in the event that a breaker fails to clear a fault as follows:

4.3.1 Breaker failure protection shall be initiated by each of the protection groups which trip the breaker, with the optional exception of a breaker failure protection in an adjacent zone.

4.3.2 Fault current detectors shall be used to determine if a breaker has failed to interrupt a fault.

4.4 Generating Station Protection

All under- and over-frequency protection systems designed to disconnect generators from the power system shall be coordinated with automatic underfrequency load shedding programs, in accordance with the Emergency Operation Criteria (Document A-3Directory #2).

4.5 Automatic Underfrequency Load Shedding Protection Systems
4.6 HVdc Systems Protection

4.6.1 The ac portion of an HVdc converter station, up to the valve-side terminals of the converter transformers, shall be protected in accordance with these criteria.

4.6.2 Multiple commutation failures, unordered power reversals, and faults in the converter bridges and the dc portion of the HVdc link which are severe enough to disturb the bulk power system shall be detected by more than one independent control or protection group and appropriate corrective action shall be taken, in accordance with the considerations in these criteria.

4.7 This section is intentionally left blank.

4.8 This section is intentionally left blank.

5.0 Reporting of Protection Systems

5.1 Each member shall provide the Task Force on System Protection (TFSP) with advance notification of any of the member’s new bulk power system protection facilities, or significant changes in the member’s existing bulk power system protection facilities.

5.2 Each member shall also provide the TFSP with advance notification of non-member protection facilities as required per NPCC Inc. Bylaws Section IX A (2) (c).

5.3 Each new or revised protection system shall be reported to the TFSP in accordance with the Procedure for Reporting and Reviewing Proposed Protection Systems for the Bulk Power System (Document C-22).

Prepared by: Task Force on System Protection
Review frequency: 3 years

References:

- *Bulk Power System Protection Guide (Document B-5)*
- *Emergency Operation Criteria (Document A-3)*
- *Maintenance Criteria for Bulk Power System Protection (Document A-4)*
- *NPCC Glossary of Terms (Document A-7)*
- *Special Protection Systems Criteria (Document A-11)*
- *Automatic Underfrequency Load Shedding Program Relaying Guide (Document B-7)*
- *Procedure for Reporting and Reviewing Proposed Protection Systems for the Bulk Power System (Document C-22)*
- *Security Guidelines for Protection Systems IEDs (Document B-24)*

Operating Reserve

Criteria

This Document has been mapped into Directory 5 – Operating Reserve

Adopted by the Members of the Northeast Power Coordinating Council March 30, 1972, 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: September 24, 1976
Revised: May 18, 1979
Revised: May 14, 1980
Revised: November 5, 1982
Revised: December 30, 1986
Reviewed: October 10, 1990
Revised: August 26, 1992
Revised: February 14, 1996
Revised: September 1998
Revised: November 7, 2001
Revised: November 14, 2002
Revised: February 6, 2006
1.0 Purpose

In the continuous operation of electric power systems, operating capacity is required to meet forecast load, including an allowance for error, to provide protection against equipment failure which has a reasonably high probability of occurrence, and to provide adequate regulation of frequency and tie line power flow. The operating capacity in excess of that required for actual load is commonly referred to as operating reserve.

This document establishes standard terminology and minimum requirements governing the amount, availability, distribution, and shared activation of operating reserve.

The objective is to ensure a high level of reliability in the NPCC Region that is, as a minimum, consistent with the Operating Policies and Standards specified by the North American Electric Reliability Council (NERC).

2.0 Definitions

Please refer to the NPCC Glossary of Terms (NPCC Document A-07). Terms found in the Glossary are bolded here.

Minimum Requirements

3.1 Ten-Minute Reserve Requirement

The ten-minute reserve available to each Area shall at least equal its first contingency loss multiplied by the Contingency Reserve Adjustment Factor for the most recently completed quarter. Ten-minute reserve shall be sustainable as specified in section 3.7 below.

Each Area shall restore its ten-minute reserve within 105 minutes if it becomes deficient as a result of a contingency that is a reportable event, as described in NPCC Document C-09, Monitoring Procedures For Operating Reserve Criteria. Each Area shall restore its ten-minute reserve as soon as possible, and within 90 minutes if it becomes deficient and the deficiency is not a result of a contingency that is a reportable event. If an Area foresees that it cannot restore its ten-minute reserve within the times specified above, or extends beyond these times during operations, a NERC Energy Emergency Alert of the appropriate level shall be declared. This requirement shall be maintained at all times, except as noted in NPCC Document C-20, Procedures During Abnormal Operating Conditions.

3.2 Thirty-Minute Reserve Requirement

The thirty-minute reserve available to each Area shall at least equal one-half its second contingency loss. Thirty-minute reserve shall be sustainable as specified in section 3.7 below.
Each Area shall restore its thirty-minute reserve within four hours if it becomes deficient. If an Area forecasts a deficiency in thirty-minute reserve for more than four hours into the future, the Area shall take corrective actions to eliminate the deficiency. This requirement shall be maintained at all times, except as noted in NPCC Document C-20, Procedures During Abnormal Operating Conditions.

3.3 Regulating Reserve Requirement

The reserve on Automatic Generation Control in each Area shall be sufficient to meet NERC control performance standards. Except during significant frequency excursions as provided in NPCC Document A-3, Emergency Operation Criteria, automatic generation control equipment shall remain in service at all possible times to provide immediate response to sudden load changes or loss of generating equipment.

3.4 Synchronized Reserve Requirement

100 percent of an Area's ten-minute reserve requirement shall be synchronized reserve except as described below. An Area shall adjust its synchronized reserve requirement based on its ability to recover from reportable events within fifteen minutes.

This synchronized reserve requirement may be decreased to a minimum of 25 percent of the ten-minute reserve requirement based upon the Area's past performance in returning its Area Control Error (ACE) to precontingency values, or to zero, within fifteen minutes following loss of resource, in accordance with the following relationship:

The synchronized reserve requirement shall be decreased by 10 percent of the ten-minute requirement for every time a control area successfully returns its ACE to precontingency values, or to zero, following a reportable event where the resource loss is equal to or less than the magnitude of the first contingency loss. Successful recoveries that occur in the same month as a failure shall not be counted that month towards a reduced synchronized reserve requirement. However, successful recoveries subsequent to a failure can be counted in the next month provided there are no failures in that month.

The synchronized reserve requirement shall increase by 20 percent of the ten-minute reserve requirement for every time a control area fails to return its ACE to precontingency values or to zero within fifteen minutes following a reportable event where the resource loss is equal to or less than the magnitude of the first contingency loss. The maximum
3.5 Compliance with NERC Disturbance Control Standard (DCS)

Areas within NPCC shall calculate and report compliance with the Disturbance Control Standard as stipulated in Document C-09, Monitoring Procedures for Operating Reserve Criteria. The evaluation of DCS compliance for an Area shall utilize the NERC Disturbance Recovery Period of fifteen minutes and shall meet the DCS requirement 100% of the time for reportable disturbances. Each Control Area not meeting the DCS during a given quarter shall increase its ten-minute reserve requirement for the calendar quarter (offset by a month) by the Contingency Reserve Adjustment Factor.

3.6 Distribution of Reserve

Operating reserve available to an Area shall be distributed so as to ensure that it can be utilized without exceeding individual element ratings or transfer limitations.

3.7 Sustainability of Reserve

Operating reserve available to an Area, if activated, shall be sustainable for at least one hour from the time of activation.

3.8 Activation Of Inter-Area Reserve

When an Area acquires operating reserve from another Area, the provider of the operating reserve shall deliver an increase in energy equal to the amount of operating reserve acquired when the acquiring Area requests its activation. Unless the provider experiences its own contingency, the provider shall not initiate the curtailment of an existing or planned energy sale to any Area to support the activation of the operating reserve that was acquired until the contingent Area has recovered from the contingency. Under normal conditions, the recovery time of the contingent Area should not exceed the DCS requirement. Operating reserve acquired from another Area shall be sustainable as specified in section 3.7 above.

3.9 Shared Activation Of Ten-Minute Reserve

Recovery from a sudden large loss of generation can be achieved faster by jointly activating reserve in several areas. NPCC and PJM have implemented such an arrangement in order to:
• more quickly relieve the initial stress placed on the interconnected transmission system following a large loss of generation or energy purchase

• effect an improvement in reliability achieved by the faster recovery

• assist in achieving compliance with the NERC Disturbance Control Standard (DCS)

Implementation of Shared Activation of Ten-Minute Reserve is described in NPCC document C-12, Procedure for Shared Activation of Ten-Minute Reserve. The provision for assistance via the Shared Activation Of Ten-Minute Reserve Procedure shall be a reportable event, except as noted in NPCC Document C-12. A portion of the energy being provided by assisting Areas as described in NPCC Document C-12 may be extended beyond the time limits specified therein as Regional Reserve Sharing Energy, as specified in NPCC Document C-38, Procedure For Operating Reserve Assistance.

4.0 Procedures

4.1 Scheduling

4.1.1 Each Area shall ensure that sufficient resources are available such that its requirements for operating reserve are met at all times.

4.1.2 An Area shall meet its requirement for operating reserve using resources within the Area or obtain deliverable capacity from outside the Area.

4.1.3 Additional resources shall be made available to ensure the adequacy of operating reserve considering various sources of uncertainty such as, but not limited to, errors in the load forecast.

4.2 Daily Operation

4.2.1 Energy associated with operating reserve may be interchanged with the understanding that it is immediately recallable. The energy associated with reserve that is utilized to meet AGC requirements to provide satisfactory system regulation shall not be sold.

An Area acquiring energy sold out of the operating reserve of another Area:

Moved to Section 5.8 of Directory 5.
will not use this energy to augment its reserve. Resources displaced by the energy must remain available to cover for the curtailment of said energy at any time.

- must adjust its ten-minute reserve requirement to cover the larger of the Area’s first contingency loss, or the largest sum of such energy purchases, which could be withdrawn at the same time due to a single contingency or event.

- An Area acquiring energy not sold out of the operating reserve of another Area:
  - is the only Area that can use this energy to augment its reserve. The providing Area is obligated to advise the acquiring Area of any change in the surplus status of the energy.

4.2.2 When an Area foresees it will be unable to provide its operating reserve requirements, appropriate measures, as contained in NPCC Document C-20, Procedures During Abnormal Operating Conditions, shall be implemented.

4.2.3 When an Area experiences a contingency in excess of its first contingency loss, it may request other Areas, via the NYISO Shift Supervisor, to activate an appropriate amount of their ten-minute reserve.

4.2.4 When ten-minute reserve in NPCC is fully utilized, appropriate measures by the deficient Area, as contained in NPCC Document A-03, Emergency Operation Criteria, shall be implemented.

5.0 Responsibilities

5.1 Each Area is responsible for observing the criteria and procedures contained herein, identifying a loss of capacity within its Area and activating operating reserve available to that Area.

5.2 Each Area is responsible for periodically auditing operating reserve status and availability to ensure proper response at all times.

5.3 The NPCC Task Force on Coordination of Operation (TFCO) is responsible for monitoring the application of these criteria.

5.4 The NPCC Control Performance Working Group (CO-1) shall monitor total NPCC reserves as part of the ongoing Area Trouble Report process detailed in Procedure C-09, Monitoring Procedures for Operating Reserve Criteria, and report to the TFCO if levels drop below the historical norms within the NPCC region.
5.5 The NPCC Control Performance Working Group (CO-1) shall monitor compliance with the Control Performance Standards on a monthly basis and report its findings to the TFCO and NERC.

5.6 For reportable frequency deviation events, the NPCC Control Performance Working Group (CO-1) shall initiate the required data collection and reporting as required by NPCC Procedure C-11, *Monitoring Procedures for Interconnected System Frequency Response* and NERC Frequency Response Characteristic Surveys.

Lead Task Force: Task Force on Coordination of Operation

Review frequency: 3 years

References: *Emergency Operation Criteria* (NPCC Document A-03)

*NPCC Glossary of Terms* (NPCC Document A-07)

*Monitoring Procedures for Operating Reserve Criteria* (NPCC Document C-09)

*Monitoring Procedures for Interconnected System Frequency Response* (NPCC Document C-11)

*Procedure for Shared Activation of Ten-Minute Reserve* (NPCC Document C-12)

*Procedures During Abnormal Operating Conditions* (NPCC Document C-20)

*Procedure for Operating Reserve Assistance* (NPCC Document C-38)

*NERC Operating Policy 1, “Generation Control and Performance”*

*NERC Performance Standard Reference Document*
This entire Document has been mapped to
Directory D7 – Special Protection Systems

Special Protection System
Criteria

Adopted by the Members of the Northeast Power Coordinating Council November 14, 2002, based on recommendation by the Reliability Coordinating Committee, in accordance with paragraph IV, subheading (A), of NPCC Membership Agreement dated November 9, 2000 as amended to date.
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Note:
Terms in bold typeface are defined in the NPCC Glossary of Terms (Document A-7).
1.0 **Introduction**

1.0.1 This document establishes the protection criteria, and recommends minimum design objectives and practices, for Special Protection Systems. It is not intended to be a design specification. It is a statement of the objectives to be observed when developing design specifications for Special Protection Systems.

1.0.2 These criteria apply to all new Special Protection Systems (SPSs). It is recognized that SPSs existed prior to the establishment of these criteria and the predecessor Guideline. It is the responsibility of individual member systems to assess their existing SPSs and to ensure that modifications are made such that, in their judgment, the intent of these criteria are met. Similar judgment shall be used with respect to an SPS existing at the time of revision to these criteria.

1.0.3 Close coordination must be maintained among system planning, design, operating, maintenance and protection functions, since both initially and throughout their life cycle, SPSs are a multi-discipline concern.

1.0.4 Special Protection Systems are sub-divided into three types. Reference can be made to the NPCC Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2) where design criteria contingencies are described in Section 5.0; operating criteria contingencies, in Section 6.0; and extreme contingencies, in Section 7.0.

**Type I** An SPS which recognizes or anticipates abnormal system conditions resulting from design and operating criteria contingencies, and whose misoperation or failure to operate would have a significant adverse impact outside of the local area. The corrective action taken by the SPS along with the actions taken by other protection systems are intended to return power system parameters to a stable and recoverable state.

**Type II** An SPS which recognizes or anticipates abnormal system conditions resulting from extreme contingencies or other extreme causes, and whose misoperation or failure to operate would have a significant adverse impact outside of the local area. In the application of these systems, their security is the prime concern (see section 2.2 of this document). Since the SPS is installed at the discretion of the member systems,
Type III An SPS whose misoperation or failure to operate results in no significant adverse impact outside the local area. The practices contained in this document for a Type I SPS should be considered but are not required for a Type III SPS. It should be recognized that a Type III SPS may, due to system changes, become Type I or Type II.

2.0 General Criteria

The general objective for any SPS is to perform its intended function (generator rejection, load rejection, etc.) in a dependable and secure manner. In this context, dependability relates to the degree of certainty that the SPS will operate correctly when required to operate. Security relates to the degree of certainty that the SPS will not operate when not required to operate.

An SPS must recognize or anticipate the specific power system conditions associated with the intended function. The relative effects on the bulk power system of a failure to operate when desired versus an unintended operation must be weighed carefully in selecting design parameters. For example, the choice of duplication as a means of providing redundancy improves the dependability of the SPS but can also jeopardize security in that it may increase the probability of an unintended operation. This general objective can be met only if the SPS can dependably respond to the specific conditions for which it is intended to operate and differentiate these from other conditions for which action must not take place.

2.1 Considerations Affecting Dependability

2.1.1 To enhance dependability, an SPS must be designed with sufficient redundancy such that the SPS is capable of performing its intended function while itself experiencing a single failure. This redundancy is normally provided by duplication. Some aspects of duplication may be achieved by overarming, which is defined as providing for more corrective action than would be necessary if no failures are considered. The redundancy requirements for an SPS apply only with respect to its response to the conditions it is required to detect.

2.1.2 For an SPS which is composed of multiple protection groups, the risk of simultaneous failure of more than one protection group because of design deficiencies or equipment failure shall be considered, particularly if identical equipment is used in each protection group. The extent and nature of these failures shall
be recognized in the design and operation of the SPS.

2.1.3 The design of a **Special Protection System** which is composed of multiple **protection groups for redundancy** should avoid the use of components common to the groups. Areas of common exposure should be kept to a minimum to reduce the possibility of all groups being disabled by a single event or condition.

### 2.2 Considerations Affecting Security

2.2.1 An SPS shall be designed to avoid false operation while itself experiencing any credible failure.

2.2.2 An SPS should be designed to operate only for conditions which require its specific protective or control actions.

### 2.3 Considerations Common to Dependability and Security

2.3.1 **Special Protection Systems** should be no more complex than required for any given application.

2.3.2 The components and software used in **Special Protection Systems** should be of proven quality, as demonstrated either by actual experience or by stringent tests under simulated operating conditions.

2.3.3 The thermal capability of all **Special Protection System** components must be adequate to withstand the maximum short time and continuous loading conditions to which the associated power system **elements** may be subjected.

2.3.4 **Special Protection Systems** should be designed to minimize the possibility of component failure or malfunction due to electrical transients and interference or external effects such as vibration, shock and temperature.

2.3.5 Critical features associated with the operability of **Special Protection Systems**, e.g. guard signals, critical control switch and test switch positions, and trip circuit integrity, should be annunciated or monitored.

2.3.6 **Special Protection System** circuitry and physical arrangements should be carefully designed so as to minimize the possibility of incorrect operations due to personnel error.
2.3.7 **Special Protection System** self-checking facilities should not degrade the performance of the **Special Protection System**.

2.3.8 Consideration should be given to the consequences of loss of ac voltage inputs to **Special Protection Systems**.

2.3.9 When remote access to **Special Protection Systems** is possible, the design should consider the consequences of unauthorized access to the **Special Protection Systems** on their overall security and dependability.

2.3.10 Consideration should be given to the effect of the means of arming on overall security and dependability of the SPS. Arming shall have a level of security and dependability commensurate with the requirements of the SPS.

### 2.4 Operating Time

An SPS shall take corrective action within times determined by studies. Adequate time margin should be provided taking into account study inaccuracies, differences in equipment, and protection operating times.

### 2.5 Arming of an SPS

Arming is the selection, which may be external to the SPS, of desired output action based on power system conditions and recognized contingencies. Arming requirements of an SPS are normally based upon the results of system studies which take into account recognized contingencies, operating policies/procedures and current power system load/generation conditions. For a simple SPS, arming may be an on/off function. An SPS can be armed either automatically or manually.

#### 2.5.1 Automatic arming is implemented without human intervention.

#### 2.5.2 Arming is manual if the recognition, decision or implementation requires human intervention. Sufficient time with adequate margin for recognition, analysis and the taking of corrective action shall be allowed.

#### 2.5.3 An SPS should be equipped with means to enable its arming to be independently verified.

### 2.6 **Special Protection System** Testing and Maintenance

#### 2.6.1 Each SPS shall be maintained in accordance with the **Maintenance Criteria for Bulk Power System Protection**
2.6.2 The design of an SPS both in terms of circuitry and physical arrangement should facilitate periodic testing and maintenance in a manner that mitigates the risk of inadvertent operation. As an SPS may be complex and may interface with other protection systems or control systems, special attention should be placed on ensuring that test devices and test interfaces properly support a clearly defined maintenance strategy.

2.6.3 Test facilities or test procedures shall be designed such that they do not compromise the independence of the redundant design aspects of the SPS.

2.6.4 An SPS shall be functionally tested when initially placed in service and when modifications are made.

2.6.5 If a segmented testing approach is used, test procedures and test facilities shall be designed to ensure that related tests properly overlap. Proper overlap is ensured if each portion of circuitry is seen to perform its intended function, such as operating a relay, from either a real or test stimulus, while observing some common reliable downstream indicator.

2.6.6 All positive combinations of input logic and significant negative combinations must be tested regardless of the maintenance strategy used. Negative combinations of input logic are those for which no SPS action should occur. Significant refers to combinations which could occur based on realistic system conditions and recognized system contingencies.

2.6.7 Sufficient testing shall be employed to ensure that timing races do not exist within hardwired or electronic logic, and that the SPS operating time is within design limits.

2.6.8 Each time the SPS is maintained, its hardware shall be tested in conjunction with the control facilities, related computer equipment, software and operating procedures to ensure compatibility and correct operation.

2.6.9 Whenever practicable, some of the maintenance testing requirements may be met by analyzing and documenting the detailed performance of the SPS during actual events to demonstrate that the specific testing requirements have been fulfilled. Such an approach can reduce the probability of false
operation during maintenance while effectively reducing the extent of planned maintenance.

2.7 Analysis of SPS Performance

2.7.1 **Bulk power system** automatic operations must be analyzed to determine proper **Special Protection System** performance. Corrective measures must be taken promptly if the **Special Protection System** or a **protection group** within the SPS fails to operate or operates incorrectly.

2.7.2 Event recording capability should be provided to the maximum practical extent to permit analysis of system operations and **Special Protection System** performance. It is recommended that these devices be time synchronized.

3.0 Equipment and Design Considerations

3.1 Current Transformers

Current transformers (CTs) associated with **Special Protection Systems** must have adequate steady-state and transient characteristics for their intended function.

3.1.1 The output of each current transformer secondary winding must remain within acceptable limits for the connected burdens under all anticipated currents, including **fault** currents, to ensure correct operation of the **Special Protection System**.

3.1.2 The thermal and mechanical capabilities of the CT at the operating tap must be adequate to prevent damage under maximum **fault** conditions and normal or emergency system loading conditions.

3.1.3 For **protection groups** to be independent, they must be supplied from separate current transformer secondary windings.

3.1.4 Interconnected current transformer secondary wiring must be grounded at only one point.
3.2 Voltage Transformers and Potential Devices

Voltage transformers and potential devices associated with Special Protection Systems must have adequate steady-state and transient characteristics for their intended functions.

3.2.1 Voltage transformers and potential devices must have adequate volt-ampere capacity to supply the connected burden while maintaining their relay accuracy over their specified primary voltage range.

3.2.2 If a Special Protection System is designed to have multiple protection groups at a single location for redundancy, each of the protection groups must be supplied from separate voltage sources. The protection groups may be supplied from separate secondary windings on one transformer or potential device, provided all of the following requirements are met:

- Complete loss of voltage does not prevent all operation of the redundant groups;
- Each secondary winding has sufficient capacity to permit fuse protection of the circuit;
- Each secondary winding circuit is adequately fuse protected.

Special attention should be given to the physical properties (e.g. resistance to corrosion, moisture, fatigue) of the fuses used in protection voltage circuits.

3.2.3 The wiring from each voltage transformer secondary winding must not be grounded at more than one point.

3.2.4 Voltage transformer installations should be designed with due regard to ferroresonance.

3.3 Logic Systems

3.3.1 The design should recognize the effects of contact races, spurious operation due to battery grounds, dc transients, radio frequency interference or other such influences.

3.3.2 It should be recognized that timing is often critical in logic schemes. Operating times of different devices vary. Timing differences shall be recognized and accounted for in overall design.
3.4 Microprocessor-Based Equipment and Software

An SPS may incorporate microprocessor-based equipment. Information from this equipment may support other functions such as power system operations. In such cases care should be taken in the design of the software and the interface so that the support of the other functions does not degrade the SPS.

3.5 Batteries and Direct Current (dc) Supply

DC supplies associated with protection must have a high degree of dependability.

3.5.1 If a Special Protection System is designed to have multiple protection groups at a single location for redundancy, no single battery or dc power supply failure shall prevent the independent protection groups from performing the intended function. Each battery must be provided with its own charger.

3.5.2 Each battery should have sufficient capacity to permit operation of the Special Protection System, in the event of a loss of its battery charger or the ac supply source, for the period of time necessary to transfer the load to the other battery or re-establish the supply source.

3.5.3 The circuitry between each battery and its first protective device cannot be protected and therefore must possess a high degree of integrity.

3.5.4 The battery chargers and all dc circuits must be protected against short circuits. All protective devices should be coordinated to minimize the number of dc circuits interrupted.

3.5.5 The regulation of the dc voltage should be such that, under all possible charging and loading conditions, voltage within acceptable limits will be supplied to all devices.

3.5.6 Dc systems shall be monitored to detect abnormal voltage levels (both high and low), dc grounds, and loss of ac to the battery chargers. Protection systems should be monitored to detect abnormal power supply.

3.5.7 Dc systems should be designed to minimize ac ripple and voltage transients.
3.6 **Station Service ac Supply**

If a **Special Protection System** is designed to have multiple protection groups at a single location for redundancy, there shall be two sources of station service ac supply, each capable of carrying at least all the critical loads associated with the **Special Protection System**.

3.7 **Circuit Breakers**

3.7.1 Where SPS redundancy is achieved by use of independent protection groups tripping the same circuit breakers without overarming, each circuit breaker shall be equipped with two independent trip coils.

3.7.2 If SPS redundancy is achieved by overarming, dual trip coils are not mandatory.

3.7.3 The indication of the circuit breaker position in **Special Protection Systems** should reliably mimic the main contact position.

3.8 **Teleprotection**

Communication facilities required for teleprotection must have a level of performance consistent with that required of the **Special Protection System**, such as:

3.8.1 Where the design of a **Special Protection System** is composed of multiple protection groups for redundancy and each group requires a communication channel, the equipment and channel for each group should be separated physically and designed to minimize the risk of more than one protection group being disabled simultaneously by a single event or condition.

3.8.2 **Teleprotection** equipment should be monitored in order to assess equipment and channel readiness.

3.8.3 **Teleprotection** systems should be designed to assure adequate signal transmission during bulk power system disturbances, and should be provided with means to verify proper signal performance.

3.8.4 **Teleprotection** systems should be designed to prevent unwanted operations such as those caused by equipment or personnel.
3.8.5 **Teleprotection** equipment should be powered by the substation batteries or other sources independent from the power system.

3.9 **Control Cables and Wiring and Ancillary Control Devices**

Control cables and wiring and ancillary control devices should be highly dependable and secure. Due consideration should be given to published codes and standards, fire hazards, current-carrying capacity, voltage drop, insulation level, mechanical strength, routing, shielding, grounding and environment.

3.10 **Environment**

3.10.1 Means should be employed to maintain environmental conditions that are favorable to the correct performance of Special Protection Systems.

3.10.2 If a Special Protection System is designed to have multiple protection groups at a single location for redundancy, physical separation should be maintained between the protection groups in order to minimize the risk of more than one group being simultaneously disabled by fire or accidents.

3.11 **Grounding**

Station grounding is critical to the correct operation of Special Protection Systems. Consideration must be given to station ground grid design, cable shielding and equipment grounding to ensure proper Special Protection System operation and to minimize the risk of false operation from fault currents or transient voltages.

4.0 **Specific Application Considerations**

4.1 **Provision for Breaker Failure**

A Type I SPS shall include provision for breaker failure for each circuit breaker whose operation is critical to the adequacy of the action taken by the SPS with due regard to the power system conditions this SPS is required to detect. Options for the provision for breaker-failure include:

4.1.1 A design which recognizes that the breaker has not achieved or will not achieve the intended function required by the SPS and which takes independent action to achieve that function. This provision need not be duplicated and can be combined with
conventional breaker failure schemes if appropriate.

4.1.2 Overarming the SPS such that adequate action is taken even if a single breaker fails.

4.1.3 The redundancy afforded by actions taken by other independent schemes or devices.

5.0 Reporting of Special Protection Systems

Each new or modified Special Protection System must be reported to NPCC in accordance with the Procedure for NPCC Review of New or Modified Special Protection Systems (SPS) (Document C-16). In addition, each new or modified Type I or Type II Special Protection System must be reported to the Task Force on System Protection in accordance with the Procedure for Reporting and Reviewing Proposed Protection Systems for the Bulk Power System (Document C-22).

Prepared by: Task Force on System Protection

Review frequency: 3 years

References:

Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2)

Emergency Operation Criteria (Document A-3)

Maintenance Criteria for Bulk Power System Protection (Document A-4)

NPCC Glossary of Terms (Document A-7)

Procedure for NPCC Review of New or Modified Bulk Power System Special Protection Systems (Document C-16)

Procedure for Reporting and Reviewing Proposed Protection Systems for the Bulk Power System (Document C-22)
System Restoration
Criteria

Adopted by the Members of the Northeast Power Coordinating Council Inc., this mm dd, yyyy, based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Inc. Bylaws dated May 18, 2006 as amended to date.

Except where noted, this document in its entirety has been mapped to Directory #8. References to Areas and Control Areas (except those in definition of terms, have been changed to the functional model entities or other generic terms such as operating areas or areas.
NPCC System Restoration Criteria
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**Note:** Terms in **bold typeface** are defined in the NPCC Document A-07, “NPCC Glossary of Terms.”
1.0 Introduction

This document stipulates the criteria under which each Area must perform power system restoration following a major or a total blackout. These criteria are also set forth in accordance with all relevant NERC Reliability Standards. Compliance to the criteria set forth in this document by each Area, entities owning or operating the Key Facilities and the Northeast Power Coordinating Council, Inc. assures the capabilities to perform power system restoration.

The functional requirements and performance of operational monitoring and control systems, operator voice communications and data telecommunications are beyond the scope of this document, except particular requirements for system restoration.

On an annual basis, the NPCC Inc. Task Force on Coordination of Operation shall review and accept each Area’s restoration plan for viability and inter-Area coordination. The composite of the individual Area’s restoration plans, once reviewed and accepted by NPCC, comprises NPCC’s regional restoration plan.

2.0 Requirements for NPCC Regional Preparedness to Perform System Restoration

2.1 System Restoration Plans

2.1.1 Each Area shall develop and maintain a system restoration plan to restore the Area’s power system following a complete or partial system blackout.

2.1.2 Each Area’s system restoration plan shall include, as a minimum, the Area’s requirements for actions to:

2.1.2.1 identify the Area’s basic minimum power system(s);

2.1.2.2 restore off-site power to nuclear plants;

2.1.2.3 identify interconnection points as agreed to by adjacent Areas;

2.1.2.3 resynchronize islands within an Area and to adjacent power system(s) as applicable;

2.1.2.5 identify blackstart capability to meet the system restoration plan requirements;
2.1.2.6 coordinate system restoration with neighboring Areas;

2.1.2.7 coordinate system restoration with other entities within the Area;

2.1.2.8 reenergize the transmission system to major generating stations and inter-Area tie lines;

2.1.2.9 stabilize electrical islands;

2.1.2.10 maintain adequate fuel resources on site for any supplementary generators (e.g., a diesel generator) used to sustain the supply of station service in whole or in part necessary for operating key facilities; and

2.1.2.11 restore loads as necessary for voltage control during system restoration.

2.1.3 The system restoration plan shall allow flexibility in execution such that restoration can be accomplished under various scenarios and system conditions.

2.2 Training

2.2.1 Reliability Coordinators shall be trained at least annually on the strategy, priorities and procedures for implementing their system restoration plan and procedures for inter-Area power system restoration.

2.2.2 Transmission Operators shall be trained at least annually on the strategy, priorities and procedures for implementing their system restoration plan.

2.2.3 All participants with tasks unique to the implementation of the system restoration plan in an Area shall be trained in their expected tasks in the restoration process.

2.3 Control Room Requirements

2.3.1 Recognizing that blackouts are accompanied by an abnormally high volume of telephone calls, each control room in the Area associated with system restoration shall provide the means to manage and prioritize telephone calls, as required.
2.3.2 Each control room shall assure that the design and implementation of their monitoring and control systems, including its SCADA and EMS, are capable of handling an inrush of data. Such systems shall be capable of a smooth transfer following the transfer to, and supply from, control room backup power supplies (i.e., UPS-Uninterruptible Power Supply) and remain functional during periods of high volumes of alarms and data updates, such as experienced during a major disturbance.

2.4 Blackstart Capability

2.4.1 Each Area shall ensure that the quantity and location of system blackstart generating units are sufficient in size and numbers, provide redundancy, and that the generators can reliably perform in a timely manner as required by the system restoration plan.

2.4.2 To determine the adequacy of blackstart facilities, each Area shall verify through analysis the feasibility of a given blackstart facility utilizing the following assessment measures:

2.4.2.1 The blackstart facility shall meet the Area’s system restoration plan stipulated performance requirements and its capability to energize transmission circuits;

2.4.2.2 The blackstart facility shall have sufficient capacity to sustain anticipated load additions;

2.4.2.3 The blackstart facility shall be located within electrical proximity to other generating stations to initiate successful system restoration;

2.4.2.4 The blackstart facility shall be capable of absorbing reactive power upon transmission line energizations and regulating voltage within acceptable limits in a steady state condition following transmission line energizations; and

Verification through analysis to determine the feasibility of a given blackstart facility to meet the requirements above shall be done by system study, simulation or real time testing.
2.5 Basic Minimum Power System Determination

The basic minimum power system consists of one or more generating stations, transmission lines, and substations operating in the form of an island for the purpose of initiating the restoration process.

The basic minimum power system shall include the capability to:

2.5.1 utilize blackstart generators;
2.5.2 form an electrical island;
2.5.3 synchronize electrical islands; and
2.5.4 permit the continuation of the system restoration plan.

The Reliability Coordinator for an Area shall identify the Area’s basic minimum power system(s) within its system restoration plan. This determination must involve all affected parties or entities. An Area may utilize more than one basic minimum power system to initiate the restoration process.

2.6 Key Facilities

Key facilities consist of:

- Blackstart generating units;
- Underground transmission cable-infrastructure (e.g., cable pumping plants particular to transmission circuit cables that are included in the basic minimum power system);
- Substation and telecommunication sites, and
- Control center and telecommunication center facilities;

Key facilities are those that comprise the basic minimum power system.

2.7 Identification of Key Facilities and Associated Critical Components

2.7.1 The Reliability Coordinator for the Area shall identify its key facilities.
2.7.2 The owners of the key facility shall maintain a current inventory of the associated critical components.
2.7.3 Each Area shall make available to NPCC upon request its current list of key facilities and critical components.

### 3.0 Power System Restoration Event Analysis

**3.1 Reliability Coordinator Restoration Evaluation**

The Reliability Coordinator shall report on the success of its restoration plan. The report shall include an analysis addressing the performance of the restoration plan.

**3.2 Transmission Operator Restoration Evaluation**

The Transmission Operator shall report on the success of its restoration plan. The report shall include an analysis addressing the performance of the restoration plan.

### 4.0 Testing Requirements for Facilities Associated with Interconnection Points

4.1 Each Transmission Owner of facilities that connect the basic minimum power system to interconnection points as agreed to by adjacent Areas shall have a maintenance and testing program for the associated equipment required for continued and proper operation in the event of a total loss of AC supply. Upon request, a summary of the maintenance and testing records shall be provided to the Reliability Coordinator.

### 5.0 Testing Requirements for Facilities Associated with Offsite Power to Nuclear Generating Plants

5.1 Each Transmission Owner of facilities that connect the basic minimum power system to nuclear plants shall have a maintenance and testing program for the associated equipment required for continued and proper operation in the event of a total loss of AC supply. Upon request, a summary of the maintenance and testing records shall be provided to the Reliability Coordinator.

### 6.0 Testing Requirements for Critical Components Associated with Key Facilities

Critical components are tested at an established frequency and duration in order to ensure the reliable operation of key facilities. Each owner of a facility shall perform the tests outlined in Table 1 and maintain records of the testing. The NPCC Compliance Committee stipulates the reporting requirements by the Areas.
The failure of a test, or the failure of **critical components** associated with **key facilities** encountered outside of normal testing, shall be reported to the Reliability Coordinator operator within 24 hours, to ensure awareness of the Reliability Coordinator operator of exposure. In the event of a failure of a **critical component** associated with **key facilities**, report the failure to the Area and identify remedial actions to be undertaken, including the date by which the work is to be completed. Subsequent retesting is to be carried out within the originally prescribed test interval. Where a test of a **critical component** associated with a **key facility** identifies a failure, and repairs are projected to extend beyond the next testing interval, the test status will be reported as failed. A report of a test failure during the repair period is not considered to be in non-compliance.

The occurrence of an actual successful event can be considered as a completed test for the applicable period, provided it can be demonstrated that the operation of the facility during the event met the test objectives and performance of these Criteria.

### 6.1 Blackstart Generating Unit Startup (Reference: Table 1; Test BS-1)

All generating facilities designated as having **blackstart capability** shall have this capability tested annually without dependencies on power sources not available during a partial or complete system blackout. Once the facility has been started, it shall continue to demonstrate the capability by operating in a stable condition while isolated from the power system for a minimum of ten minutes. The number of units within a generating facility that shall be blackstarted for this test is determined by the Area as needed by the Area’s system restoration plan.

Each Area shall ensure that **blackstart** generation facilities complete a successful **blackstart** test consistent with the objectives of the Area’s system restoration plan.

All operating aids and auxiliary systems used in **blackstarts**, such as operations voice communications and system control and data acquisition (SCADA), shall be verified to operate adequately without dependency on the interconnected system or other unrelated unit support for any source of station service.

### 6.2 Backup Pressurization System of Underground Transmission Cables (Reference: Table 1; Test UG-1)

Certain underground transmission cables require a pressurized insulating medium to maintain dielectric strength. The capability to do so during a blackout is essential to maintain the availability of such underground cables for service and to preclude any damage to the cables upon energizing. This capability shall be tested
either by testing the cable’s backup pressurization system or by powering the
cable's normal pressurizing system from a backup power source (e.g. backup
generator). This test shall be conducted every six (6) months by demonstrating
that the required pressures can be maintained for a minimum of thirty (30)
minutes.

6.3 Substation and Telecommunication Backup Power Supplies-Batteries and
Generators (Reference: Table 1; Tests ST-1 to ST-6)

Backup power supplies in substations and telecommunication sites, which are
deemed critical to system restoration, shall be tested as specified below. Where
there are separate backup power arrangements at a site for substation equipment
and telecommunication equipment they shall be separately identified in the
critical components listing and shall be inspected and tested individually.

6.3.1 The required tests are as follows:

6.3.1.1 Battery charger and batteries shall be inspected annually and meet
owner / operator battery integrity standards. (Reference: Table 1;
Test ST-1)

6.3.1.2 Interruption of AC supply to a battery charger shall be carried out
annually to ensure a battery picks up and carries load.
Alternatively, a discharge test may be performed. (Reference:
Table 1; Test ST-2)

6.3.1.3 Each entity’s design and commissioning requirements must ensure
that all critical loads are supplied from batteries and battery
charger as part of their engineering and design. If, and when,
modifications are made, and/or every five years, each entity shall
reconfirm through their design review and/or through testing that
all critical loads are connected to the battery and the battery
charger. (Reference: Table 1; Test ST-3)

6.3.1.4 Performance testing of batteries in substations and
telecommunication sites shall be done at least once every five (5)
years. A recognized discharge (load) test will be conducted at
least once every five years for a minimum of two hours. The
success of this test is when average/individual cell voltage does not
drop below prescribed design limits for the specific battery type.
(Reference: Table 1; Test ST-4)
6.3.1.5 For substations and telecommunication sites provided with backup power generators, a startup and run test shall be performed monthly for a minimum run time of fifteen (15) minutes. (Reference: Table 1; Test ST-5)

6.3.1.6 For substations and telecommunication sites provided with backup power generators, verify that the generators will pickup the required load during the loss of station service, a startup, transfer and run test simulating the loss of station service will be performed annually for a duration of at least thirty (30) minutes. (Reference: Table 1; Test ST-6)

6.4 Control Center and Telecommunication Center Facilities (Reference: Table 1; Tests CC-1 To CC-5)

• Testing of facilities in control centers and telecommunication centers shall be performed in order to demonstrate the computer systems will be functional when required for system restoration, without dependencies on power sources unavailable during a partial or complete system blackout. The uninterruptible power supply (UPS) systems in control centers and telecommunication centers shall be tested annually by interrupting AC supply and verifying that all critical loads are supplied for a time that is sufficient for backup power sources to restore the AC input to the UPS. (Reference: Table 1; Test CC-1)

• Performance testing of batteries in substations and telecommunication sites shall be done at least once every five (5) years. A recognized discharge (load) test will be conducted at least once every five years for a minimum of two hours. The success of this test is when average/individual cell voltage does not drop below prescribed design limits for the specific battery type. (Reference: Table 1; Test ST-4)

• For control centers and telecommunication centers provided with a backup power generator, a startup and run test shall be performed monthly for at least fifteen (15) minutes. (Reference: Table 1; Test CC-3)

• For control centers and telecommunication centers provided with a backup power generator, verify that the generators will pick up the required load (including heating, ventilation and air conditioning (HVAC) for computer systems) during the loss of station service. A startup, transfer and run test simulating the loss of station service shall be performed annually for a duration of at least thirty (30) minutes. During the test, the operation of the auxiliaries shall be verified. (Reference: Table 1; Test CC-4)
• Each Area shall test its computer redundancy features every six (6) months to ensure computer systems continue to function adequately. (Reference: Table 1; Test CC-5)
## Table 1 - Standard Test Procedures for key facilities and associated critical components required for system restoration

<table>
<thead>
<tr>
<th>Test No.</th>
<th>Critical Component</th>
<th>Test</th>
<th>Test Frequency and Duration</th>
<th>Criteria for Successful Test</th>
</tr>
</thead>
<tbody>
<tr>
<td>BS-1</td>
<td>Blackstart</td>
<td>Startup test of generating unit <strong>blackstart capability</strong> without dependencies on the power system</td>
<td><strong>Frequency:</strong> annual <strong>Duration:</strong> 10 minutes of stable operation</td>
<td>Successful startup and 10 minutes of stable operation All operating aids and auxiliary systems are independent.</td>
</tr>
<tr>
<td></td>
<td>Generating Units</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>UG-1</td>
<td>Pressurization</td>
<td>Test backup pressurization system by switching from normal to backup pressurization scheme or test cable's normal pressurization system from a backup power source (e.g. backup generator)</td>
<td><strong>Frequency:</strong> every 6 months <strong>Duration:</strong> minimum of 30 minutes; verify that backup pressurization system or backup generator is able to maintain dielectric strength of insulating medium for the expected time required for restoration</td>
<td>Maintains safe dielectric pressure for the minimum test period Backup pressurization system or backup generator can maintain dielectric of insulating medium for the expected time required for system restoration</td>
</tr>
<tr>
<td></td>
<td>system of</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td></td>
<td>underground</td>
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<td></td>
<td>transmission</td>
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<tr>
<td></td>
<td>Cables</td>
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</thead>
<tbody>
<tr>
<td>ST-1</td>
<td>Battery charger and batteries in substation and Telecommunication site</td>
<td>Check battery integrity as per owner / operator maintenance practices</td>
<td>Frequency: annually</td>
<td>Meet owner / operator battery integrity standards</td>
</tr>
<tr>
<td>ST-2</td>
<td>Battery charger and batteries in substation and Telecommunication site</td>
<td>Interruption of AC supplies to battery charger to ensure that battery picks up and carries <strong>load</strong></td>
<td>Frequency: annually</td>
<td>Maintain acceptable voltage levels for the duration of the test</td>
</tr>
<tr>
<td>ST-3</td>
<td>Battery charger and batteries in substation and Telecommunication site</td>
<td>Confirm by design review and/or testing that all critical <strong>loads</strong> are connected to the battery via commissioning requirements and when modifications are made or if practicable, interruption of AC station service.</td>
<td>Frequency: once every 5 years or when modifications are made</td>
<td>Confirm that all critical <strong>loads</strong> are supplied from battery charger and batteries.</td>
</tr>
<tr>
<td>Test No.</td>
<td>Critical Component</td>
<td>Test</td>
<td>Test Frequency and Duration</td>
<td>Criteria for Successful Test</td>
</tr>
<tr>
<td>---------</td>
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<td>------------------------------</td>
</tr>
<tr>
<td>ST-4</td>
<td>Batteries in substation and telecommunication site</td>
<td>recognized performance test of battery capacity</td>
<td>Frequency: at least once every five years Duration: minimum 2 hours</td>
<td>The success of this test is when average/individual cell voltage does not drop below prescribed design limits for the specific battery type.</td>
</tr>
<tr>
<td>ST-5</td>
<td>Backup generator in substation and Telecommunication site</td>
<td>Startup and run test for backup generator</td>
<td>Frequency: monthly Duration: minimum of 15 minutes</td>
<td>Successful startup followed by 15 minutes of stable operation</td>
</tr>
<tr>
<td>ST-6</td>
<td>Backup generator in substation and Telecommunication site</td>
<td>Backup generator startup, transfer and run test to simulate loss of station service</td>
<td>Frequency: annually Duration: minimum of 30 minutes</td>
<td>- Successful startup - Transfer scheme operates correctly - 30 minutes of stable operation supplying critical loads</td>
</tr>
<tr>
<td>Test No.</td>
<td>Critical Component</td>
<td>Test</td>
<td>Test Frequency and Duration</td>
<td>Criteria for Successful Test</td>
</tr>
<tr>
<td>---------</td>
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</tr>
</tbody>
</table>
| CC-1    | Uninterruptible power supply (UPS) system in control center and Telecommunication center | Interruption of AC supply to UPS to ensure it can continue to support all critical loads | **Frequency:** annually  
**Duration:** for a time that is sufficient for backup power sources to restore AC supply to the UPS | No impact on computer or telecommunication functions during testing |
| CC-2    | Batteries in control center and telecommunication center | recognized performance test of battery capacity | **Frequency:** at least once every five years  
**Duration:** minimum 2 hours | The success of this test is when average/individual cell voltage does not drop below prescribed design limits for the specific battery type. |
Table 1 - Standard Test Procedures for key facilities and associated critical components required for system restoration

<table>
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<tr>
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</tr>
</thead>
<tbody>
<tr>
<td>CC-3</td>
<td>Backup generator in control center and Telecommunication center</td>
<td>Startup and run test for backup generator</td>
<td>Frequency: monthly Duration: minimum of 15 minutes</td>
<td>Successful startup followed by 15 minutes of stable operation</td>
</tr>
</tbody>
</table>
| CC-4     | Backup generator in control center and Telecommunication center | Backup generator startup, transfer and run test to simulate loss of station service | Frequency: annually Duration: minimum of 30 minutes | - Successful startup  
- Transfer scheme operates correctly  
- 30 minutes of stable operation supplying loads critical to system restoration  
- When HVAC system restarts, ambient temperature is in the range of equipment working temperature |
### Table 1 - Standard Test Procedures for key facilities and associated critical components required for system restoration

<table>
<thead>
<tr>
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<th>Critical Component</th>
<th>Test</th>
<th>Test Frequency and Duration</th>
<th>Criteria for Successful Test</th>
</tr>
</thead>
</table>
| CC-5     | Computer systems           | Verify computer redundancy or (n-1) check by failing over the EMS    | Redundancy check every 6 months      | - No impact on computer functions during testing.  
- Successful switching / testing without equipment failure. |
Content in this Document has been mapped to Directory 9. Detailed mapping is shown in text boxes on the margin throughout this document.

NPCC Inc. Verification of Generator Gross and Net Real Power Capability

Adopted by the Members of the Northeast Power Coordinating Council on 07 18, 2007 based on recommendations by the Reliability Coordinating Committee, in accordance with paragraph VIII, subheading (a), of the NPCC Inc. Bylaws dated May 18, 2006 as amended to date.
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Appendix

Basic Flow Chart for Verification of Generator Gross and Net Real Power
Capability .................................................................................. 7

**Note:** Terms in **bold typeface** are defined in the NPCC Document A-07, “NPCC Glossary of Terms.”
1.0 Introduction

This document establishes the minimum criteria to verify the Gross Real Power Capability and Net Real Power Capability of generators used to ensure accuracy of information used in the steady-state models to assess the reliability of the NPCC bulk power system. These criteria have been developed to ensure that the requirements specified in NERC Standard MOD-024-1, “Verification of Generator Gross and Net Real Power Capability” are met by NPCC and its applicable members responsible for meeting the NERC standards.

The Gross Real Power Capability of a generator or generation facility for the purpose of Document A-13 is defined as the maximum megawatt output at the generator terminals, at the normally expected system conditions for that seasonal capability period.

The Net Real Power Capability of a generator or generation facility for the purpose of the Document A-13 is defined as the Gross Real Power Capability, less the auxiliary real power loads necessary to operate the generator at maximum real power output.

A Generator’s Declared Capability, for the purpose of the Document A-13, is defined as the values submitted by the Generator Owner to the respective Area.

2.0 General Requirements

2.1 Each Area shall apply these criteria to all generators included in its Area reliability assessments.

2.2 Each Area shall identify and maintain documentation of those generators subject to periodic seasonal Gross Real Power Capability and Net Real Power Capability verification. The documentation maintained by each Area shall, as a minimum, include the following:

2.2.1 Listing of all generators or generation facilities and their declared Gross Real Power Capability and Net Real Power Capability.

2.2.2 Listing of all generators or generation facilities verified Gross Real Power Capability and Net Real Power Capability, verification date and method of verification.

2.2.3 Listing for each generator or generation facility discrepancies between a Generator Owner’s declared and verified Gross Real Power Capability and Net Real Power Capability (see 2.5 and 2.6 for specifics)

2.2.4 Copies of Generator Owner supplied Gross Real Power Capability and Net Real Power Capability testing, manufacture data, performance tracking or operating historical data certification documentation as specified by the Area.

2.2.5 Listing of generators exempted from the verification requirements and the basis for their exemption (see 3.2 and 4.0).
2.3 Each Area shall establish and maintain a program in accordance with the criteria outlined in this Document to periodically verify the Gross Real Power Capability and Net Real Power Capability of all generators and generation facilities subject to periodic seasonal Gross Real Power Capability and Net Real Power Capability verification. Any change made to the program after it has been established shall be reported to NPCC and the Generator Owner within 30 days.

2.4 Each Generator Owner shall comply with the Areas requests for periodic verification of Gross Real Power Capability and Net Real Power Capability of their generators as outlined in this Document.

2.5 Each Generator Owner shall determine and report the generator or generation facility real power seasonal auxiliary loads (including common station loads) to the Area.

2.6 Each Area shall document any discrepancies between system modeling and generator verified capabilities and the reason for such discrepancies.

2.7 Each Area shall establish notification requirements for a Generator Owner to notify its Area within a specified time period when its generator or generation facility cannot achieve the previous verified real power capability because of equipment or system issues.

2.8 The NPCC Task Force on Coordination of Operations and Task Force on Coordination of Planning shall annually review the Area’s Gross Real Power Capability and Net Real Power Capability verification program to ensure the program is meeting the intent of these criteria.

3.0 Specific Criteria

3.1 Each Area shall verify the seasonal Gross Real Power Capability and Net Real Power Capability of all generators or generation facilities subject to periodic seasonal Gross Real Power Capability and Net Real Power Capability verification as specified in Section 5.0. The two (2) capability seasons are defined as summer and winter as specified by the Area.

3.1.1 If an Area determines that only one seasonal generating capability value will suffice for NPCC Bulk Power System reliability analysis, then periodic verification will be required only for that particular season.

3.1.2 If an Area determines that the difference between Gross Real Power and Net Real Power Capability of a generator or generation facility is...
insignificant for NPCC Bulk Power System reliability analysis, then periodic verification will be required for only one numerical value.

3.2 The Area shall verify the generator or generation facility seasonal Gross Real Power Capability and Net Real Power Capability as specified in Section 3.3 of this Document and applicable NERC Standards.

If a Generator Owner cannot perform verification testing for the required seasonal period, the generator shall be exempted from testing for one or more of the following reasons:

3.2.1 Adverse impact on transmission system reliability
3.2.2 Potential damage to transmission system or generator equipment
3.2.3 Environment conditions
3.2.4 Governmental regulatory or operating license limitations

A generator or generation facility exempted from seasonal capability testing shall submit certified generator operation records, manufacture data, commissioning data (for new generators only) or performance tracking for the same previous seasonal verification period as required by the Area.

3.3 The following criteria shall apply for determination of a generator’s or generation facility’s Gross Real Power Capability and Net Real Power Capability, as applicable to the types of generators and generation facilities for the required periods as described in sections below.

3.3.1 Thermal Generators

The verification of Gross Real Power Capability and Net Real Power Capability of a generator shall be determined on the basis of operation for no less than two consecutive hourly periods. Determination of thermal generator’s capability can include testing, use of operating historical data, commissioning data (for new generators only) and performance tracking data acquired during the same seasonal capability testing period.

3.3.2 Internal Combustion Generators and Gas Turbine Generators

The verification of Gross Real Power Capability and Net Real Power Capability for internal combustion generators and gas turbine generators shall correspond to the ambient conditions normally expected for the seasonal period for which the Gross Real Power Capability and Net Real Power Capabilities are being claimed for no less than one hour.
Determination of internal combustion and gas turbine generator’s capability can include testing, use of operating historical data, commissioning data (for new generators only) and performance tracking data acquired during the same seasonal capability period.

### 3.3.3 Hydro Generators

a. Hydro capability shall be determined on a generation facility or an individual generator basis.

b. The **Gross Real Power Capability** and **Net Real Power Capability** shall be determined on the basis of the availability of sufficient water at an adequate head to provide the output for no less than two consecutive hourly periods.

c. Determination of Hydro generator’s capability can include testing, use of operating historical data, commissioning data (for new generators only) and performance tracking data acquired during the same seasonal capability period.

### 3.3.4 Combined Cycle Generators

a. Combined cycle generator capability shall be determined on a generation facility, individual generator or on a generator stage basis.

b. Verification of **Gross Real Power Capability** and **Net Real Power Capability** for combined cycle generators shall correspond to the ambient conditions normally expected for the seasonal period for which the **Gross Real Power Capability** and **Net Real Power Capabilities** are being claimed for no less than one hour.

c. Determination of combined cycle generator’s capability can include testing, use of operating historical data, commissioning data (for new generators only) and performance tracking data acquired during the same seasonal capability period.

### 3.3.5 Intermittent Power Resources

For intermittent power resources (wind, solar, tidal or geo-thermal generators) the manufacturer’s data, performance tracking and operating historical data shall be used to determine generator or generation facility **Gross Real Power Capability** and **Net Real Power Capability**.
3.4 Determination of **Gross Real Power Capability** and **Net Real Power Capability** for multiple generator facilities when limited by common elements shall be based on the real power capability of the facility and not the sum of the capabilities of the individual generators.

3.5 The Generator Owner shall identify any equipment, system or other factor that has the potential to limit the capability of the generator or generation facility to meet its declared **Gross Real Power Capability** and **Net Real Power Capability**.

3.6 Upon notification of a discrepancy between its declared and verified **Gross Real Power Capability or Net Real Power Capability**, the Generator Owner shall provide the **Area** a plan to resolve any **Gross Real Power Capability or Net Real Power Capability** discrepancy, as required by the **Area**.

3.7 Each **Area** shall report to **NPCC** annually any discrepancies between declared and verified **Gross Real Power Capability or Net Real Power Capability**.

### Responsibilities

4.0 **Responsibilities**

4.1 **NPCC**

4.1.1 Shall annually validate that each **Area** has implemented the **Gross Real Power Capability and Net Real Power Capability** verification program.

4.1.2 Shall, through periodic compliance audits, review the effectiveness of the **Areas’ Gross Real Power Capability and Net Real Power Capability** verification program.

4.1.3 Ensure compliance to the criteria in this document.

4.1.4 Ensure that any disagreements among the parties shall be addressed in accordance with the **NPCC Dispute Resolution Process**.

4.2 **Area**

4.2.1 Responsible for reviewing and implementing the **Gross Real Power Capability and Net Real Power Capability** verification program within its **Area**.
4.2.2 Responsible for reporting annually to NPCC about the status of its program including any changes in verification process related to verification of Gross Real Power Capability and Net Real Power Capability.

4.2.3 Responsible to ensure that any discrepancy between a Generator Owner’s declared and verified Gross Real Power Capability or Net Real Power Capability is addressed in a time frame as specified by the Area.

4.2.4 Responsible for maintaining documentation on exempted generators and verification records for verified generators or generation facilities.

4.2.5 Provide copies of any changes to the Area’s Gross Real Power Capability and Net Real Power Capability verification process to the Generator Owners, Transmission Operators, Planning Authorities, Transmission Planners and NPCC Task Forces on Coordination of Operations and Task Force on Coordination of Planning within 30 days of issue.

4.3 Generator Owner

4.3.1 Responsible for providing generator or generation facility declared Gross Real Power Capability and Net Real Power Capability as required by the Area.

4.3.2 Responsible for addressing any discrepancies between declared and verified Gross Real Power Capability or Net Real Power Capability within time frame specified by the Area.

5.0 Verification Schedule

5.1 Generator and generation facility Gross Real Power Capability and Net real Power Capability shall be re-verified every three (3) years or as required by the Area. (see section 3.2 for testing limitations/considerations)

5.2 Re-verification of a generator or generation facility that did not meet its declared capability shall be scheduled within a time frame as required by the Area.

Prepared by: NPCC Task Force on Coordination of Operation / Task Force on Coordination of Planning

Review frequency: 3 years
References:

NPCC Glossary of Terms (NPCC Inc. Document A-07)

NERC Standard MOD-024-1, “Verification of Generator Gross and Net Real Power Capability”


References are not mapped since all relevant materials are now incorporated into Directory 9.
Appendix:

Basic Flow Chart for Verification of Generator Gross and Net Real Power Capability

This diagram has been mapped to Appendix B in Directory 9.
NPCC INC.

Verification of Generator
Gross and Net Reactive Power Capability

Content in this Document has been mapped to Directory 10. Detailed mapping is shown in text boxes on the margin throughout this document.
TABLE OF CONTENTS

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2.0 General Requirements

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1.0 Introduction

This Document establishes the minimum criteria to verify the **Gross Reactive Power** and **Net Reactive Power Capability** of generators to ensure accuracy of information used in the steadystate models to assess the reliability of the NPCC bulk power system. These criteria have been developed to ensure that the requirements specified in **NERC Standard MOD-025-1**, “Verification of Generator Gross and Net Reactive Power Capability”, are met by NPCC and its applicable members that are required to comply with the **NERC** standards.

The **Gross Reactive Power Capability** of a generator or generation facility for the purpose of this Document is defined as the maximum lagging and leading reactive capability at the generator terminals and at the **Area**’s specified Gross Real Power output during the seasonal capability period. In the event that a generator or generation facility cannot achieve a leading megavar output because of unit or system limitation, then the **Area** may require the generator to verify its minimum lagging reactive capability.

The **Net Reactive Power Capability** of a generator or generation facility for the purpose of this Document is defined as **Gross Reactive Power Capability** adjusted for any applicable losses and auxiliary loads incurred up to the point of interconnection and at the **Area**’s specified Gross Real Power output during the seasonal capability period.

A “**Generator Owner’s Declared Reactive Power Capability**”, for the purpose of this Document is defined as the reactive power lagging and leading capability values submitted by the Generator Owner to the respective **Area**.

A “**Generator Owner’s Verified Reactive Power Capability**”, for the purpose of this Document is defined as the reactive power lagging and leading capability as demonstrated by the methods specified herein.

A “**Generation Facility**” for the purpose of this Document is defined as multiple generating units, which are modeled as a single entity by the **Area**.

2.0 General Requirements

2.1 Each **Area** shall identify generators and generation facilities that are subject to seasonal **Gross Reactive Power** and **Net Reactive Power Capability** verification and apply these criteria to all identified generators and generation facilities. The verified data shall be used as the maximum gross and net reactive power capability of generators and generation facilities for steady state models and may also be used for other reliability assessments.
2.2 For those identified generator or generation facilities each Area shall maintain as a minimum the following documentation:

2.2.1 Listing of generators or generation facilities and their declared Gross Reactive Power and Net Reactive Power Capability and seasonal auxiliary reactive power requirements. (Reference Appendix B for recommended generator or generation facility’s information to be provided by the generator owner.)

2.2.2 Listing of generators or generation facilities verified Gross Reactive Power and Net Reactive Power Capability, verification date and method of verification.

2.2.3 Listing of discrepancies between system modeling, declared and verified Gross Reactive Power and Net Reactive Power Capability and the reason for such discrepancies.

2.2.4 Listing of generators and generation facilities exempted from the verification testing requirements and basis for their exemption (see section 3.7).

2.3 Each Area shall establish and maintain a program in accordance with the criteria outlined in this Document to periodically verify the Gross Reactive Power and Net Reactive Power Capability of all generators and generation facilities subject to periodic seasonal Gross Reactive Power and Net Reactive Power Capability verification. Any change made to the program after it has been established shall be reported to NPCC and the Generator Owners within 30 days.

2.4 Each Generator Owner shall comply with the Area’s requests for periodic verification of Gross Reactive Power and Net Reactive Power Capability of their generators or generation facilities as outlined in this Document.

2.5 Each Generator Owner shall determine and report to the Area the generator or generation facility’s seasonal Gross Reactive Power and Net Reactive Power Capabilities and seasonal reactive auxiliary load requirements.

2.6 Generator Owner shall retain Gross Reactive Power and Net Reactive Power Capability testing, commissioning or performance tracking data with any supplemental engineering analysis as specified by the Area for the most current and prior verification period.

2.7 Each Area shall establish notification requirements for a Generator Owner to notify its Area within a specified time period when its generator and generation facility cannot achieve the previously verified reactive power capability because of any equipment limitation.
3.0 Specific Criteria

3.1 Each Area shall verify the seasonal Gross Reactive Power and Net Reactive Power Capability of all generators and generation facilities subject to seasonal Gross Reactive Power and Net Reactive Power Capability verification as specified in this Document and applicable NERC Standards. The two (2) capability seasons are defined as summer and winter as specified by the Area.

3.1.1 If an Area determines that only one seasonal generating capability value will suffice for NPCC Bulk Power System reliability analysis, then periodic verification will be required only for that particular season.

3.1.2 If an Area determines that the difference between Gross Reactive Power and Net Reactive Power Capability of a generator or generation facility is insignificant for NPCC Bulk Power System reliability analysis, then periodic verification will be required for only one numerical value.

3.1.3 If an Area determines that only lagging or leading Gross Reactive Power and Net Reactive Power Capability of a generator or generation facility is required for NPCC Bulk Power System reliability analysis, then periodic verification will be required for that specific reactive power capability value.

3.1.4 Verification of a single unit is acceptable as a representative for multiple generators of same type and design at a common location for intermittent or small units as specified by an Area.

3.2 Verification of a generator’s lagging and leading reactive capabilities can be demonstrated for that seasonal capability verification period at a real power level equivalent to that specified in sections 3.3 and 3.4 by:

- testing,
- use of performance tracking with any required supplemental engineering analysis, or,
- commissioning data (for new generators only) acquired.

3.3 Lagging Reactive Power Capability testing will normally be performed during on-peak hours. Lagging Reactive Power capability testing shall be performed at a real power level as specified by the Area.
Leading Reactive Power Capability testing will normally be performed during off-peak hours. Leading Reactive Power Capability testing shall be performed at a real power level as specified by the Area.

3.4 The following criteria shall apply for verification of a generator’s Gross Reactive Power and Net Reactive Power Capability, as applicable to the types of generators and for the required verification periods as described in sections below:

3.4.1 Thermal Generators, Internal Combustion Generators, Gas Turbine Generators, Combined Cycle and Hydro Generators

The verification of Gross Reactive Power and Net Reactive Power Capability of a generator shall be determined from the average leading reactive power output for at least a 15 consecutive minute period and average lagging reactive power output for a 60 consecutive minute period.

3.4.2 Intermittent Power Resources

For intermittent power resources (wind, tidal or geo-thermal generators) the manufacturers’ or commissioning data can be used until sufficient performance tracking data is available to verify generator or generation facilities lagging and leading reactive capabilities.

3.4.3 Generators Operating as Synchronous Condensers

The verification of Gross Reactive Power and Net Reactive Power Capability of a generator that has the capability of being used as a synchronous condenser (this testing shall be conducted at zero MW output) shall be determined from the average leading and reactive power output for at least 15 consecutive minute period and average lagging reactive power output for a 60 consecutive minute period.

3.5 Determination of Gross Reactive Power and Net Reactive Power Capability for a generation facility when limited by common elements shall be based on the reactive power capability of the generation facility and not the sum of the capabilities of the individual generators.

3.6 If the generator or generator facility is unable to reach its declared lagging or leading seasonal Gross Reactive Power and Net Reactive Power Capability during testing or by use of performance data, the Area and Generator Owner shall evaluate the cause of the limitation. The Area shall document the reasons that prevented the generator or generation facility from achieving its declared capability and determine if retesting is required during that seasonal period.
3.7 If prior to performing the verification testing it is determined that the generator or generation facilities cannot perform the verification testing for the required seasonal verification period, the Area may exempt the generator from testing for one or more of the following reasons:

3.7.1 Adverse impact on transmission system reliability

3.7.2 Potential damage to transmission system, or generator equipment

3.7.3 Governmental regulatory or operating license limitations

The generator or generation facility exempted from seasonal capability testing shall submit certified generator performance tracking, manufacturer’s or commissioning data (for new generators only) from the previous applicable seasonal verification period as required by the Area. Engineering analysis may be used in conjunction with performance tracking data to justify any difference between a generator’s or generation facility’s declared capability and previous seasonal performance data.

The generator or generation facility and the Area shall coordinate the rescheduling of verification testing for the next seasonal verification period or as mutually agreed upon.

3.8 The Generator Owner shall identify and notify the Area of any equipment, system or other factors that will limit the capability of the generator or generation facility to meet its declared Gross Reactive Power and Net Reactive Power Capability.

3.9 Upon notification of a discrepancy between verified and declared Gross Reactive Power and Net Reactive Power Capability, the Generator Owner shall provide the Area a plan to resolve any discrepancy or revise its declared reactive power capability.

4.0 Responsibilities

4.1 NPCC INC

4.1.1 Shall annually validate that each Area has implemented the Gross Reactive Power and Net Reactive Power Capability verification program.

4.1.2 Shall, through periodic compliance audits, review the effectiveness of the Areas’ Gross Reactive Power and Net Reactive Power Capability verification program.
4.1.3  Shall ensure compliance to the criteria in this Document.

4.1.4  Shall ensure that any disagreements among the parties are addressed in accordance with the Area Dispute Resolution Process.

4.1.5  The NPCC Task Force on Coordination of Operations and Task Force on Coordination of Planning shall annually review each Area’s Gross Reactive Power and Net Reactive Power Capability verification program to ensure the program is meeting the intent of these criteria.

4.1.6  Shall retain both the current and previous versions of this Document.

4.2  Area

4.2.1  Shall develop, implement and review the Gross Reactive Power and Net Reactive Power Capability verification program within its Area. The program shall be reviewed on a 3-year cycle.

4.2.2  Shall ensure that any discrepancy between a Generator Owner’s declared and verified Gross Reactive Power and Net Reactive Power Capability is addressed in a time frame as specified by the Area.

4.2.3  Shall ensure that any disagreements among the parties are addressed in accordance with the applicable Dispute Resolution Process.

4.2.4  Shall maintain documentation on exempted and verified generators and generation facilities.

4.2.5  Shall notify the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, Transmission Planners and NPCC Task Forces on Coordination of Operations and Task Force on Coordination of Planning within 30 days of issue of any changes to the Area’s Gross Reactive Power and Net Reactive Power Capability verification program.

Generator Owner

4.3.1  Shall determine and report the generator or generation facility’s declared Gross Reactive Power and Net Reactive Power Capability as required by the Area.
4.3.2 Shall address any discrepancies between declared and verified Gross Reactive Power and Net Reactive Power Capability within a time frame specified by the Area.

4.3.3 Shall retain Gross Reactive Power and Net Reactive Power Capability testing, commissioning data or performance tracking data with any supplemental engineering analysis as specified by the Area for the current and most recent prior verification period.

5.0 Verification Schedule

5.1 Initial verification of Gross Reactive Power and Net Reactive Power Capability shall be implemented at a minimum, in accordance with MOD-025 section A-05.

5.2 Generator and generation facility’s Gross Reactive Power and Net Reactive Power Capability shall be re-verified at least every five years.

5.3 Re-verification of a generator or generation facility that did not meet its declared capability shall be scheduled within a time frame as required by the Area.

Lead Task Forces: Task Force on Coordination of Planning/ Task Force on Coordination of Operation
Reviewed for concurrence by: TFCO, TFSP, TFSS and TFIST Chairman
Review frequency: 3 years

References:

- NPCC Document A-07, “NPCC Glossary of Terms”

Appendix: A - Basic Flow Chart for Verification of Generator Gross and Net Reactive Power Capability

Appendix: B - Generator Reactive Capability Data Form

APPENDIX A
Basic Flow Chart for Verification of Generator Gross and Net Reactive Power Capability

Generator verification is required

Exempted from seasonal verification

Notify Generator Owners

Generator Owners provide operating or test data

Area determines if data is adequate to verify

Gross and Net verified

Document units/ data

Retest or re-declare reactive capability

Mapped to Appendix B-1 of Directory 10.
**GENERATOR REACTIVE CAPABILITY DATA FORM** *(Moved to Appendix B-2 in D10)*

### 1. Data Preparation Documentation*

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<th>Unit No.</th>
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<th>Generator Owner</th>
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<td>12234</td>
<td>Big Power</td>
<td>Jim Smith</td>
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**Prepared By**

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<th>Effective Date</th>
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<th>Contact e-mail</th>
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<td><a href="mailto:john@bigpower.com">john@bigpower.com</a></td>
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### Auxiliary Reactive Power Requirements

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### Reactive Data*

**Seasonal Data**

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<tr>
<td>Leading Capability</td>
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<td>250</td>
<td>230</td>
</tr>
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</table>

---

*Data inputted for illustration purposes,*

**T- Testing; P- Performance Tracking; C-Commissioning data**

**Notes and Limitations:**

(1) Full MVAR capability could not be achieved because of system voltage restriction. Engineering analysis was provided to demonstrate unit was capable of declared values.

**Generating unit capability curve.** Please attach a .jpg image from the generating unit capability D curve
Mapping of Selected Guidelines to Directory D2 – Emergency Operations

Guidelines for Inter-AREA Voltage Control

Approved by the Operating Procedure Coordinating Committee and the System Design Coordinating Committee on May 27, 1981

Revised:
- March 15, 1983
- May 14, 1985
- February 8, 1989
- December 8, 1992
- November 6, 1997
1.0 Introduction

This guideline provides general principles and guidance for effective inter-Area voltage control, consistent with the NPCC Basic Criteria (NPCC Document A-2) and NERC Policy 2. Specific methods to implement these guidelines may vary among Areas, depending on local requirements. Coordinated inter-Area voltage control is necessary to regulate voltages to protect equipment from damage and prevent voltage collapse. Coordinated voltage regulation reduces electrical losses on the network and lessens equipment wear and tear. Local control actions are generally most effective for voltage regulation. Occasions arise when adjacent Areas can assist each other to compensate for deficiencies or excesses of reactive power and improve voltage profiles and system security.

2.0 Principles

Each Area shall develop, and operate in accordance with, its own voltage control procedures and criteria. Area procedures and criteria shall be consistent with NPCC and NERC Criteria and Guidelines. Adjacent Areas should be familiar with each others criteria and procedures. Areas shall mutually agree upon procedures for inter-Area voltage control. Whether inter-Area voltage control is carried out through specific or general procedures, the following should be considered and applied:

2.1 to effectively coordinate voltage control, location and placement of metering for reactive power resources and voltage controller status must be consistent between adjacent Areas.

2.2 availability of voltage regulating transformers in proximity of tie lines

2.3 voltage levels, limits, and regulation requirements for stations on either side of an inter-Area interface.

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

2.5 tie line reactive losses as a function of real power transfer

2.6 reactive reserve of on-line generators

2.7 shunt reactive device availability and switching strategy.

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

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

3.1 **Normal Voltage Conditions**

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

- actual voltages are within applicable normal (pre-contingency) voltage ranges
- expected post-contingency voltages are within applicable post-contingency minimum and maximum levels following the most severe NPCC Normal Criteria Contingency.

3.1.1 Each Area shall provide for the supply and control of its reactive regulation requirements, including reactive reserve so that applicable emergency voltage levels can be maintained following NPCC Normal Criteria Contingencies.

3.1.2 Providing that it is feasible to regulate reactive flows on its tie lines, each Area may establish a mutually agreed upon normal schedule of reactive power flow with adjacent Areas and with neighboring systems in other Reliability Councils. This schedule should conform to the provisions of the relevant interconnection agreements and may provide for:

- the minimum and maximum voltage at stations at or near terminals of inter-Area tie lines
- the receipt of reactive flow at one tie point in exchange for delivery at another
- the sharing of the reactive requirements of tie lines and series regulating equipment (either equally or in proportion to line lengths, etc.)
- the transfer of reactive power from one Area to another
3.1.3 Each Area will anticipate voltage trends and initiate corrective action in advance of critical periods of heavy and light loads.

3.2 Abnormal Voltage Conditions

The bulk power system is operating with Abnormal Voltage Conditions when:

- actual voltages are outside applicable normal (pre-contingency) voltage ranges.

- expected post-contingency voltages violate applicable post-contingency minimum and maximum levels following applicable NPCC Normal or Emergency Criteria Contingencies.

3.2.1 If the bulk power system voltage is rapidly decaying, the Area, if identifiable, causing the decay shall immediately implement all possible action, including the shedding of firm load, to correct the problem. All other Areas experiencing the rapid voltage decay will immediately implement all possible action, including the shedding of firm load, to correct the problem, until such time that the Area causing the decay has implemented actions to correct the problem.

3.2.2 When an Area anticipates or is experiencing an abnormal, but stable, or gradually changing bulk power system voltage condition, it shall implement steps to correct the situation. Recognizing that voltage problems are most effectively corrected by control actions as close to the source as possible, the Area shall use its own resources, but may request assistance from adjacent Areas. Sections 3.2.3 to 3.2.8 provide a guide for the implementation of potential control actions with the provision that individual steps may be eliminated if considered ineffective for the particular situation.
3.2.3 The Area anticipating or experiencing the abnormal bulk power system voltage condition shall implement the following control actions, where effective and as available, in accordance with the Areas respective voltage control procedures:

- adjust transformer taps
- switch capacitors/reactors
- adjust static Var compensators
- utilize full reactive capability of on-line generators
- deploy synchronous condensers
- other actions as local voltage control procedures allow

3.2.4 If the steps in Section 3.2.3 are insufficient to correct the problem, adjacent Areas shall be advised of the need to depart from normal reactive schedules and shall be requested to provide assistance if this will be effective. The adjacent Areas shall assist by using some or all of the control actions listed in Section 3.2.3 where effective and as available, in accordance with the adjacent Area’s voltage control procedures.

3.2.5 If the steps in Sections 3.2.3 and 3.2.4 are insufficient to correct the problem, the Area experiencing the abnormal voltage condition shall take the following actions, where effective and as available, in accordance with the Area’s respective voltage control procedures:

- modify economy transactions with other Areas, and/or deviate from economic dispatch
- operate hydraulic units as synchronous condensers, where possible
- reschedule pumped hydro units to generate or motor over the critical period
- purchase energy
- reduce generator real power output to increase reactive capability
• start additional generation
• switch out internal transmission lines provided operating security limits are not violated

3.2.6 If the steps listed in Section 3.2.5 fail to correct the problem, the Area experiencing the bulk power system voltage problem shall request adjacent Areas to assist by using some or all of the steps listed in Section 3.2.5 where effective and as available.

3.2.7 If the steps listed in Section 3.2.5 and 3.2.6 are insufficient to correct the problem, the Area experiencing the problem shall reduce customer supply voltage if this will improve transmission voltage levels. If, after this step, additional assistance is required, adjacent Areas shall be requested to reduce customer supply voltage if this will be effective, providing the Area in difficulty has already taken this step.

3.2.8 If the problem is low voltage and it persists after the steps of Section 3.2.7 are exhausted, or if the bulk power system voltage is rapidly decaying, the Area in difficulty will shed firm load as required.

3.2.9 When assistance is provided by adjacent Areas, Emergency Transfer Criteria shall not be exceeded.

3.2.10 If two or more Areas are experiencing voltage problems simultaneously, they will assist each other as above to the extent feasible. If the problem is so severe as to require the shedding of firm load, the shedding shall be done to the extent required to control the situation. Areas that have mutually agreed upon a normal schedule of reactive power flow, as in Section 3.1.2 above shall adhere to this schedule to the extent possible.

Coordinated by: Task Force on Coordination of Operation
Reviewed for concurrence by: TFCP and TFSS
Review Frequency: 3 years
Guidelines for NPCC Area Transmission Reviews

Approved by the System Design Coordinating Committee and the Operating Procedure Coordinating Committee on February 10, 1976

Revised:

June 14, 1982
August 26, 1985
December 13, 1988
December 10, 1991
December 14, 1993
August 7, 1996
November 7, 2001
September 7, 2005
March 5, 2008
1.0 General Requirement

NPCC has established a Reliability Assessment Program to bring together work done by the Council, its member systems and Areas relevant to the assessment of bulk power system reliability. As part of the Reliability Assessment Program, the Task Force on System Studies (TFSS) is charged on an ongoing basis with conducting periodic reviews of the reliability of the planned bulk power transmission system of each Area of NPCC and the transmission interconnections to other Areas. The purpose of these reviews is to determine whether each Area’s planned bulk power transmission system is in conformance with the NPCC Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2). Since it is NPCC’s intention that the Basic Criteria be consistent with the NERC Planning Standards, conformance with the NPCC Basic Criteria assures consistency with the NERC Planning Standards. Terms in bold typeface are defined in the NPCC Glossary of Terms (Document A-7).

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

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

The purpose of the presentation associated with an Area Transmission Review is to demonstrate that the Area’s planned transmission system, based on its projection of available resources, is in conformance with the NPCC Basic Criteria. By such a presentation, the Task Force will satisfy itself that the criteria have been met and, in general, that the reliability of the NPCC Interconnected Systems will be maintained. Analysis of this material should include a review of Special Protection Systems, as well as an assessment of the potential for widespread cascading due to overloads, instability or voltage collapse. In addition, the potential consequences of failure or misoperation of Dynamic Control Systems (DCSs), which include Transmission Control Devices as defined in the NERC Planning Standards, should be addressed.

This review by the TFSS does not alter Area and/or Company responsibilities with respect to their system's conformity with the NPCC Basic Criteria.

3.0 The Study Year to be Considered

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

4.0 Types and Frequency of Reviews

Each Area is required to present an annual transmission review to TFSS. However, the review presented by the Area may be one of three types: a Comprehensive (or Full) Review, an Intermediate (or Partial) Review, or an Interim Review.

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

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

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

In March of each year, each Area shall present to the TFSS a proposal for the type of review to be conducted that year. TFSS will consider each Area’s proposal and either indicate their concurrence, or require the Area to conduct a more extensive review if the Task Force feels that such is warranted based on the Area’s system changes since its last Comprehensive Review. Area Interim Review reports shall be presented to TFSS by the end of that calendar year, and Area Intermediate and Comprehensive Review reports shall be presented to TFSS by April of the following year.

5.0 Format of Presentation

5.1 Comprehensive or Intermediate Review

5.1.1 Introduction

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

b) Describe the type and scope of this review.

c) For a Comprehensive Review, describe the existing and planned bulk power system facilities included in this review.

d) Describe changes in system facilities, schedules and loads since the most recent Comprehensive Review.
e) Include maps and one-line diagrams of the system showing proposed changes as necessary.

f) Describe the selected demand levels over the range of forecast system demands.

g) Discuss projected firm transfers and interchange schedules.

5.1.2. Study results Demonstrating Conformance with Section 5.0 of the NPCC Basic Criteria entitled, "Transmission Design Criteria", which includes evaluation of contingencies after any critical generator, transmission circuit, transformer, series or shunt compensating device or HVDC pole has already been lost.

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

b) Steady State Assessment

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

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

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

- Discuss the load flows showing the effects of major planned changes on the system.
Discuss applicable transfer limits between contiguous areas.

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

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

c) Stability Assessment

Discuss and/or refer to significant studies showing the effect on the system of contingencies as specified in Section 5.1 of the Basic Criteria, entitled "Stability Assessment" and report on the most severe contingencies in the following manner:

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

- Nature of fault, elements switched, switching times.

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

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

- Include the effects of existing and planned control devices.

- Include in the study the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.
For a Comprehensive or Intermediate Review, discuss the load model and other modeling assumptions used in the analysis. (An Intermediate Review may refer to the discussion from the last Comprehensive Review.)

d) Fault Current Assessment

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

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

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

5.1.3. Extreme Contingency Assessment

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

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

c) Discuss and/or refer to significant load flow studies showing the base case and the post fault conditions for the contingencies as specified in Section 7.0 of the Basic Criteria, entitled "Extreme Contingency Assessment". Report on the most severe contingencies tested.

d) Discuss and/or refer to significant stability studies showing the effect on the system of contingencies as specified in Section 7.0 of the Basic Criteria. Report on the most severe contingencies tested.
e) In the case where contingency assessment concludes serious consequences, conduct an evaluation of implementing a change to address such contingencies.

5.1.4. Extreme System Condition Assessment

a) Discuss the scope of the analyses.

b) Discuss and/or refer to significant load flow studies showing the effect on the steady state performance of extreme system conditions as specified in Section 8.0 of the Basic Criteria, entitled "Extreme System Condition Assessment". Report on the most severe system conditions and contingencies tested.

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

d) Discuss and/or refer to significant stability studies showing the effect on the dynamic performance of extreme system conditions as specified in Section 8.0 of the Basic Criteria. Report on the most severe system conditions and contingencies tested.

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

5.1.5. Review of Special Protection Systems (SPSs)

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

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

d) For instances where an SPS which was formerly considered to have only local consequences is identified as having the potential for inter-Area effects, for the time period being reviewed, the TFSS should notify the Task Forces on Coordination of Planning, System Protection and Coordination of Operation. In such instances a complete review of the SPS should be made, as per the *Procedure for NPCC Review of New or Modified Bulk Power System Special Protection Systems (SPS)* (Document C-16).

5.1.6. Review of Dynamic Control Systems (DCSs)

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

5.1.7. Review of Exclusions to the Basic Criteria

Review any exclusions granted under the *NPCC Guidelines for Requesting Exclusions to Sections 5.1(b) and 6.1(b) of the NPCC Basic Criteria for Design and Operation of Interconnected Power Systems* (Document B-10). A Comprehensive Review should address all exclusions, but an Intermediate Review may focus on just those exclusions that may have been impacted by system changes since they were last reviewed.

5.1.8. Overview Summary of System Performance for Year Studied

5.2. Interim Review

5.2.1. Introduction of Interim Review

Section 5.2 moved to section 6.0 of Appendix B of Directory #1.
Reference the most recent Comprehensive Review and any subsequent Intermediate or Interim Reviews as appropriate.

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

a) Load Forecast

b) Generation Resources

c) Transmission Facilities

d) Special Protection Systems

e) Dynamic Control Systems

f) Exclusions

5.2.3. Brief Impact Assessment and Overview Summary

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

6.0 Documentation

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

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

7.1 Once an **Area** has presented its Review report to the TFSS, TFSS will review the Area’s report and any supporting documentation and:

a. Consider whether to accept the report as complete and in full conformance with these Guidelines. If the report is found to be unacceptable, TFSS will indicate to the **Area** the specific areas of deficiency, and request the **Area** to address those deficiencies.

b. Consider their concurrence with the results and conclusion(s) of the **Area’s** Review. If there is not concurrence, TFSS will indicate to the **Area** the specific areas of disagreement, and work with the **Area** to try to achieve concurrence. If agreement has not been reached within a reasonable period of time, TFSS shall prepare a summary of the results of its review, including a discussion of the areas of disagreement.

7.2 If the results of the **Area** Review indicates that the Area’s planned bulk power transmission system is not in conformance with the NPCC Basic Criteria, TFSS will request the **Area** to develop a plan to achieve conformance with the Criteria.

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

7.4 Upon completion of an Area Review, TFSS will report the results of the review to the Task Force on Coordination of Planning and to the Reliability Coordinating Committee.
Coordinated by: Task Force on System Studies

Reviewed for concurrence by: TFCO and TFCP

Review frequency: 3 years

References:
- Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2)
- NPCC Glossary of Terms (Document A-7)
- NPCC Reliability Compliance and Enforcement Program (Document A-8)
- Procedure for Analysis and Classification of Dynamic Control Systems (Document C-33)
- Guidelines for Requesting Exclusions to Sections 5.1(b) and 6.1(b) of the NPCC Basic Criteria for Design and Operation of Interconnected Power Systems (Document B-10).
- Procedure for Testing and Analysis of Extreme Contingencies (Document C-18)
**Note:**

Terms in bold typeface are defined in the *NPCC Glossary of Terms* (Document A-7)
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1.0 Introduction

This document complements the NPCC Bulk Power System Protection Criteria, Document A-5 and provides guidance for consideration in the implementation of the A-5 criteria. The sections of this document are organized in the same order as A-5 to facilitate easy reference between the two documents (but only the main headings). Some sections may be left blank for this reason.

1.1 This section is intentionally left blank.

1.2 Responsibility

Close coordination should be maintained among planning, design, operating, maintenance and protection functions with the intent that modifications or additions to the bulk power system will result in facilities that are adequately protected and can be operated and maintained reliably and safely.

2.0 General Guidance

In general, the function of a protection system is to limit the severity and extent of system disturbances and possible damage to system equipment. The intent of the A-5 criteria is to ensure that protection systems are designed to perform this function in accordance with the protection dependability and security levels implicit in the Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2).

The A-5 criteria objectives can be met only if protection systems have a high degree of dependability and security. In this context dependability relates to the degree of certainty that a protection system will operate correctly when required to operate. Security relates to the degree of certainty that a protection system will not operate when not required to operate.

Often increased security (fewer unintended operations) results in decreased dependability (more failures to operate), and vice versa. As an example, consideration is given to the consequence of applying permissive line protection schemes, which often are more secure, but less dependable, than blocking line protection schemes.

2.1 Issues Affecting Dependability
2.1.1. Some portions of elements may not in themselves be part of the bulk power system. Those portions do not require two protection groups.

2.1.2. Two identical measuring relays should not be used in independent protection groups due to the risk of simultaneous failure of both groups because of design deficiencies or equipment problems.

2.1.3. Areas of common exposure should be kept to a minimum to reduce the possibility of both groups being disabled by a single event such as fire, excavation, water leakage, and other such incidents.

2.1.4. On installations where free-standing or column-type current transformers are provided on one side of the breaker only, resulting in a protection blind spot, protection should be provided to detect a fault to ground on the primaries of such current transformers. When frame ground protection is used, then frame ground and breaker failure protections are the two local independent protections for the blind spot between the current transformer and the circuit breaker. Neither of these protections need be duplicated. Both of these protections should be designed so as to not be disabled by the same failure. The frame ground protection and breaker failure protection will in fact provide independent protections for the blind spot.

2.2 Issues Affecting Security

2.2.1. For faults external to the protected zone, each protection group should be designed either to not operate, or to operate selectively with other groups and with breaker failure protection.

2.2.2. For planned system conditions, protection systems should not operate to trip for stable power swings.

2.3 Issues Affecting Dependability and Security

2.3.1. Protection systems should be no more complex than required for any given application.

2.3.2. The components and software used in protection systems should be of proven quality, as demonstrated either by actual experience or by stringent tests under simulated operating conditions.
2.3.3 **Protection systems** should be designed to minimize the possibility of component failure or malfunction due to electrical transients and interference or external effects such as vibration, shock and temperature.

2.3.4 **Protection system** circuitry and physical arrangements should be designed so as to minimize the possibility of incorrect operations due to personnel error.

2.3.5 **Protection system** automatic self-checking facilities should be designed so as to not degrade the performance of the **protection system**.

2.3.6 Consideration should be given to the consequences of loss of instrument transformer voltage inputs to **protection systems**.

2.3.7 **Protection systems**, including intelligent electronic devices (IEDs) and communication systems used for **protection**, should comply with applicable industry standards for utility grade **protection** service. Utility Grade Protection System Equipment are equipment that are suitable for protecting transmission power system elements, that are required to operate reliably, under harsh environments normally found at substations. Utility grade equipment should meet the applicable sections of all or some of the following types of industry standards, to ensure their suitability for such applications:

- IEEE C37.90.1-2002 (oscillatory surge and fast transient)
- IEEE C37.90.1-2002 (service conditions)
- IEC 60255-22-1, 2005 (1 MHz burst, i.e. oscillatory)
- IEC 61000-4-12, 2001 (oscillatory surge)
- IEC 61000-4-4, 2004 (EFT)
- IEC 60255-22-4, 2002 (EFT)
- IEEE C37.90.2-2004 (narrow-band radiation)
- IEC 60255-22-3, 2000 (narrow-band radiation)
- IEC 61000-4-3, 2002 (narrow-band radiation)
- IEEE 1613 (communications networking devices in Electric power Substations)

2.4 **Operating Time**
Adequate time margin should be provided taking into account study inaccuracies, differences in equipment, and protection operating times. In cases where clearing times are deliberately extended, consideration should be given to the following:

- Effect on system stability or reduction of stability margins.
- Possibility of causing or increasing damage to equipment and subsequent extended repair and/or outage time.
- Effect of disturbances on service to customers.

2.5 This section is intentionally left blank.

2.6 Protection System Testing and Maintenance

Test facilities and test procedures should be designed such that they do not compromise the independence of protection groups protecting the same bulk power system element. Test devices or switches should be used to eliminate the necessity for removing or disconnecting wires during testing.

2.7 Analysis of Protection Performance

Insofar as possible, each active protective function within a protective relay should provide separate target information.

3.0 Equipment and Design Considerations

3.1 This section is intentionally left blank.

3.2 Voltage Transformers and Potential Devices

Voltage transformer installations should be designed with due regard to ferroresonance.

3.2.1 Special attention should be given to the physical properties (e.g. resistance to corrosion, moisture, fatigue) of the fuses used in protection voltage circuits.

3.3 Logic Systems

The design should recognize the effects of contact races, spurious operation due to battery grounds, dc transients, radio frequency interference or other such influences.
It is recognized that timing is often critical in logic schemes. Operating times of different devices vary. Known timing differences should be accounted for in the overall design.

3.4 Microprocessor-Based Equipment and Software

A protection system may incorporate microprocessor-based equipment. Information from this equipment may support other functions such as power system operations. In such cases, the software and the interface should not degrade the protection system functions.

3.5 Batteries and Direct Current (dc) Supply

The circuitry between each battery and its first protective device cannot be protected and therefore should be designed so as to minimize the possibility of electrical short circuit.

The design for the regulation of the dc voltage should be such that, under all anticipated charging and loading conditions, voltage within acceptable limits will be supplied to all devices, while minimizing ac ripple and voltage transients.

3.6 This section is intentionally left blank.

3.7 Circuit Breakers

The indication of the circuit breaker position in protection systems should be designed to reliably mimic the main contact position.

3.8 Teleprotection

Teleprotection systems should be designed to prevent unwanted operations such as those caused by equipment or personnel.

Two identical teleprotection equipments should not be used in independent protection groups, due to the risk of simultaneous failure of both groups because of design deficiencies or equipment problems.

Areas of common exposure should be kept to a minimum to reduce the possibility of both groups being disabled by a single event such as fire, excavation, water leakage, and other such incidents.

3.8.1 Teleprotection systems should be designed to mitigate the effects of signal interference from other communication sources
and to assure adequate signal transmission during bulk power system disturbances.

3.9 Control Cables and Wiring and Ancillary Control Devices

Control cables and wiring and ancillary control devices should be highly dependable and secure. Due consideration should be given to published codes and standards, fire hazards, current-carrying capacity, voltage drop, insulation level, mechanical strength, routing, shielding, grounding and environment.

3.10 Environment

Means should be employed to maintain environmental conditions that are favorable to the correct performance of protection systems.

3.11 This section is intentionally left blank

4.0 Specific Application Considerations

4.1 Transmission Line Protection

For planned system conditions, line protection systems associated with transmission facilities should not operate to trip for stable power swings.

4.2 Transmission Station Protection

The protection systems should operate properly for the anticipated range of currents.

For planned system conditions, all station protection systems should not operate for load current or stable power swings.

In particular, load responsive protective relays applied to transmission autotransformers should allow all possible loadability, consistent with equipment protection requirements.

Fault pressure or Buchholz relays used on transformers, phase shifters or regulators should be applied so as to minimize the likelihood of their misoperation due to through faults.
4.3 Breaker Failure Protection

4.3.1 It is not necessary to duplicate the breaker failure protection itself.

4.3.2 Auxiliary switches may also be required in instances where the fault currents are not large enough to operate the fault current detectors. In addition, auxiliary switches may be necessary for high-speed detection of a breaker failure condition.

4.4 Generating Station Protection

4.4.1 Each protection system should be designed to minimize the effects to the bulk power system of faults and disturbances, while itself experiencing a single failure.

4.4.2 Generators should be protected to limit possible damage to the equipment. The following are some of the abnormal (not necessarily fault) conditions that should be detected:

- Unbalanced phase currents, loss of excitation,
- overexcitation, generator out of step, field ground,
- and inadvertent energization.

4.4.3 Protections for the above conditions in section 4.4.2, which are applied for equipment protection, need not be duplicated.

4.4.4 When a directional overcurrent or distance relay is applied to remove the generator for slowly cleared faults on the external system, such protection is a backup and does not need to be duplicated.

4.4.5 The apparatus should be protected when the generator is starting up or shutting down as well as running at normal speed; this may require additional relays as the normal relays may not function satisfactorily at low frequencies.

4.4.6 Generator protection systems should not operate for stable power swings except when that particular generator is out of step with the remainder of the system. This does not apply to Special Protection Systems designed to trip the generator as part of an overall plan to maintain stability of the power system.
4.4.7 Loss of excitation and out of step relays should be set with due regard to the performance of the excitation system.

4.4.8 It is recognized that the overall protection of a generator involves non-electrical considerations that have not been included as a part of the criteria.

4.4.9 All overfrequency, overvoltage and undervoltage protection systems designed to disconnect generators from the power system should be coordinated with automatic underfrequency load shedding programs.

4.5 Automatic Underfrequency Load Shedding Protection Systems

4.5.1 Automatic underfrequency load shedding protection systems are not generally located at bulk power system stations; however, they have a direct effect on the operation of the bulk power system during major emergencies.

4.5.2 Automatic underfrequency load shedding protection need not be duplicated.

4.6 HVdc Systems Protection

4.6.1 Converter terminals should be protected to avoid excessive equipment stresses and to minimize equipment damage and outage time. These protections are usually specific to the design of the converter station(s) and are determined by the manufacturer to comply with availability guarantees. The following are some conditions which should be detected:
- ac and dc undervoltage,
- ac and dc overvoltage,
- valve misfire,
- excessive harmonics on the dc,
- dc ground faults and open circuits,
- dc switching device failures,
- thyristor failures,
- valve, and snubber circuit overloads.

4.6.2 The overall protection and control of an HVdc link may also involve the initiation of actions in response to abnormal conditions on the ac interconnected system. The control and
protection systems associated with such conditions are not considered part of the HVdc systems protection.

4.7 Capacitor Bank Protection

4.7.1 Each protection system should be designed to minimize the effects to the bulk power system of faults and disturbances, while itself experiencing a single failure.

4.7.2 Capacitor bank protection should be applied with due consideration for capacitor bank transients, power system voltage unbalance, and system harmonics.

4.7.3 Protection may be provided to minimize the impact of failures of individual capacitor units on the remaining capacitor units, however, these types of protections do not need to be duplicated:

a. Overvoltage Protection
b. Individual fuses for each capacitor unit
c. Overvoltage Protection for each capacitor unit.

4.8 Static Var Compensator (SVC) Protection

4.8.1 The low voltage branch circuits contain the reactive controlling equipment, filters, etc. These may include all or some of the following:

a. Thyristor Controlled Reactors (TCR)
b. Thyristor Switched Capacitors (TSC)
c. Switched or Fixed Capacitors
d. Harmonic Filters

4.8.2 Protection for the branch circuits that are not part of the bulk power system need not be duplicated. Protection for these branch circuits should be applied with due consideration for capacitor bank transients, power system voltage unbalance, and system harmonics.

4.8.3 Protection against abnormal non-fault conditions within the SVC via control of the TSC and TCR valves shall be designed so as to not interfere with the proper operation of the SVC.

5.0 This section is intentionally left blank.
Prepared by: Task Force on System Protection

Review frequency: 3 years

References:


Emergency Operation Criteria (Document A-3)

Maintenance Criteria for Bulk Power System Protection (Document A-4)

Bulk Power System Protection Criteria (Document A-5)

NPCC Glossary of Terms (Document A-7)

Special Protection Systems Criteria (Document A-11)

Automatic Underfrequency Load Shedding Program Relaying Guide (Document B-7)

Procedure for Reporting and Reviewing Proposed Protection Systems for the Bulk Power System (Document C-22)

Security Guidelines for Protection Systems IEDs (Document B-24)

Automatic Underfrequency Load Shedding Program Relaying Guideline

Sections 2.0 and 3.0 of this document have been mapped to Section 2.17 in Appendix B of Directory 4 – Bulk Power System Protection Criteria. The remaining materials of this document, which are of general nature, have been dropped.

Approved by the Reliability Coordinating Committee on March 2, 1999

Note: This Document supersedes the Automatic Load Shedding Employing Underfrequency Threshold Relays (Document B-6) and the Application of Underfrequency Protection (Document B-7), which were approved by the System Design Coordinating Committee and the Operating Procedure Coordinating Committee on November 25, 1983, and May 23, 1984, respectively.

Revised: November 14, 2002
March 9, 2005
September 4, 2008
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Note:
   Terms in bold typeface are defined in the NPCC Glossary of Terms (Document A-7).
1.0 Introduction

The frequency of a power system will change when the load-generation equilibrium is disturbed. If the unbalance is caused by a deficiency of generation, the system frequency will decay to a value at which load-generation equilibrium is reestablished. If equilibrium cannot be established, system collapse will occur.

When the power system's self-regulation is insufficient to promote the establishment of a stable state, the system frequency will continue to decay unless some means is provided to force a load-generation balance. Automatic underfrequency load shedding is the accepted means of reestablishing this load-generation balance within the time constraints necessary to avoid system collapse.

The acceptable boundaries of frequency decay and the magnitude of the load to be shed by the automatic underfrequency load shedding program are determined by comprehensive tests on models of the system taking into account established load rejection practices.

The NPCC Emergency Operation (Directory #2) sets forth the requirements for automatic underfrequency load shedding and automatic underfrequency load shedding associated with generator underfrequency tripping. This guide presents relay application and testing requirements necessary to accomplish the objectives of Directory #2.

It is essential that sufficient generation remain in service so that the objective of the automatic underfrequency load shedding program is achieved. It must be recognized that generating units may trip during underfrequency conditions due to loss of plant auxiliary equipment. For example, the flow of coolant through a nuclear reactor of either the pressurized water or boiling water design may be affected by changes in reactor coolant pump or feedwater pump speed caused by underfrequency transients. The requirements for maintaining coolant flow must be considered when determining underfrequency trip setpoints for nuclear generating units.

2.0 Underfrequency Relay Application

In this guideline, underfrequency relays which operate at a discrete frequency value are called “underfrequency threshold relays.”
Selection of underfrequency sensing devices should be on a threshold basis. Alternatively, rate of change of frequency load shedding may be used when the requirements of the Area indicate that this method will achieve the intent of the load shedding program. Appropriate studies are necessary to determine the application and settings of the rate of change of frequency relays for a particular Area.

2.1 Uniform Response

In order for each entity to shed approximately the same proportion of load, given the same frequency condition, all styles and manufacture of underfrequency relays must trip at essentially the same time. For electromechanical relays, time delay depends on rate of frequency decline, and it is not possible to achieve uniform response for different rates of decline. The recommendations in this guideline are based on the goal of a uniform response at a rate of frequency decline of 0.2 Hz per second.

2.2 Additional Application Considerations

2.2.1 Where undesired underfrequency relay operation can be caused by decaying frequency due to isolated generation or motor load, additional supervising undercurrent or voltage relays may be used to prevent misoperation.

2.2.2 Where the AC voltage source for an underfrequency relay is derived from a potential device connected to a cable circuit, care should be taken to estimate the voltage present during de-energization of the circuit. The natural frequency of the decaying cable voltage may be less than 60 Hz, and thus cause an incorrect relay operation.

2.2.3 The AC Voltage Inhibit feature available on some relays may be useful as a security tool to restrain operation during cable de-energization, depending on the voltage decay time constant.

2.2.4 Due regard should be given to the expected power system voltage during events for which the underfrequency relays are expected to operate. The relay’s minimum AC voltage operating characteristic should not inhibit proper relay operation, nor should the Voltage Inhibit feature, where it exists, be set to prevent proper operation.
3.0 Setting and Maintenance Recommendations

3.1 Pickup & Time Delay Settings

Pickup and time delay settings of underfrequency threshold relays should be applied in accordance with the requirements of Section 5.2 and Section 5.4 of the Emergency Operation (Directory #2).

3.2 Relay Performance Requirements

Any electromechanical underfrequency relay which has been found to have drifted more than ±0.2 Hz from its set point or ±0.1 seconds from its time delay should be recalibrated and then retested in six months. If, at that time, the relay has drifted ±0.2 Hz or more from its set point or ±0.1 seconds or more from its fixed time delay, the cause of the drift should be corrected or the relay should be replaced.

3.3 Maintenance

Protection required by the NPCC automatic underfrequency load shedding program has a direct effect on the operation of the bulk power system during major emergencies. As such, this protection must be maintained in compliance with the NPCC Maintenance Criteria for Bulk Power System Protection (Directory #3), even though the relays are usually located in non-bulk power system stations.

4.0 Annual Review & Documentation

The NPCC Reliability Compliance and Enforcement Program (Document A-8) requires periodic review by each NPCC Area of their automatic underfrequency load shedding capability and generator underfrequency tripping. This review shall be documented in a manner and form designated by the Compliance Committee.
| Maintenance Criteria for Bulk Power System Protection (Directory #3) |
| NPCC Glossary of Terms (Document A-7) |
| NPCC Reliability Compliance and Enforcement Program (Document A-8) |
Guidelines for Area Review of Resource Adequacy

Approved by the System Design Coordinating Committee and the Operating Procedure Coordinating Committee on October 7, 1983

Revised: September 1, 1987
Revised: December 11, 1990
Revised: November 8, 1994
Revised: February 14, 1996
Revised: June 28, 2001
Revised: November 29, 2005
**Introduction**

NPCC has established a Reliability Assessment Program to bring together work done by the Council, its member systems and Areas relevant to the assessment of bulk power system reliability. As part of the Reliability Assessment Program, the Task Force on Coordination of Planning is charged, on an ongoing basis, with conducting reviews of resource adequacy of each Area of NPCC. (Terms in bold typeface are defined in the Glossary located in Document A-7, the NPCC Glossary of Terms).

Resources refer to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include all generation sources within an Area and purchases from neighboring systems. Demand-side facilities include measures for reducing or shifting load, such as conservation, load management, interruptible loads, dispatchable loads and small identified (unmetered at control centers) generation.

The NPCC role in monitoring conformance with the NPCC Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2) is essential because, under this criterion, each Area determines its resource requirements by considering interconnection assistance from other Areas, on the basis that adequate resources will be available in those Areas. Because of this reliance on interconnection assistance, inadequate resources in one Area could result in adverse consequences in the other Areas.

It is recognized that all Areas may not necessarily express their own resource adequacy criterion as stated in the NPCC Basic Criteria. However, the NPCC Basic Criteria provides a reference point against which an Area's resource adequacy criterion can be compared.

The NPCC will not duplicate reviews and studies completed by member systems and Areas. The NPCC may reference these Reviews in appropriate NPCC reports.

**Purpose of Presentation**

The purpose of the presentation associated with a resource adequacy review is to ascertain that each Area's proposed resources are in accordance with the NPCC Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2). By such a presentation, the Task Force will satisfy itself that the proposed resources of each NPCC Area will meet the NPCC Resource Adequacy - Design Criteria (as defined in Section 3.0 of NPCC Document A-2) over the time period under consideration. This review by the Task Force on Coordination of Planning does not replace Area and/or company responsibility to assess their systems in conformity with the NPCC Basic Criteria.

**Time Period to be Considered**

The time period to be considered for an Area’s Comprehensive Resource Review will be five years and be undertaken every three years to focus on installed capacity requirements. In subsequent years, the Area shall conduct Annual Interim Reviews that will cover, at a minimum, the remaining years studied in the Comprehensive Review. Based on the results
of the Annual Interim Review, the CP-8 Working Group may recommend to the TFCP that the **Area** conduct the next Comprehensive Review at a date earlier than specified above.

**General Statement on Confidentiality**

NPCC will respect the confidentiality requirements imposed within each **Area** and will not publish nor disclose commercially sensitive information without the consent of the information owner, unless such information is suitably aggregated with other data to mask the individual company information.

**Format of Presentation and Report – Comprehensive Review**

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

### 1.0 Executive Summary

1.1 Briefly illustrate the major findings of the review.

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

### 2.0 Table of Contents

2.1 Include listing of all tables and figures.

### 3.0 Introduction

3.1 Reference the previous NPCC **Area** review.

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

### 4.0 Resource Adequacy Criterion

4.1 State the **Area**'s **resource** adequacy criterion.

4.2 State how the **Area** criterion is applied; e.g., load relief steps.

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

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

4.5 Discuss **resource** adequacy studies conducted since the previous **Area** review, as appropriate.
5.0 Resource Adequacy Assessment

5.1 Evaluate proposed resources versus the requirement to reliably meet projected electricity demand assuming the Area’s most likely load forecast.

5.2 Evaluate proposed resources versus the requirement to reliably meet projected electricity demand assuming the Area’s high load growth scenario.

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

6.0 Proposed Resource Capacity Mix

6.1 Discuss any reliability impacts resulting from the proposed resources fuel supply and transportation and/or environmental restrictions.

6.2 Describe available mechanisms to mitigate any potential reliability impacts of resource fuel supply and transportation issues and/or environmental restrictions.

Format of Presentation and Report – Annual Interim Review

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

The Area will provide a brief assessment of the impact of these changes on the reliability of the interconnected bulk power system. This assessment should be based on engineering judgment, internal system studies and appropriate joint interconnected studies.

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

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

A. Description of Resource Reliability Model

1.1 Load Model
1.1.1 Description of the load model and basis of period load shapes.

1.1.2 How load forecast uncertainty is handled in model.

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

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

1.2 Resource Unit Representation

1.2.1 Unit Ratings

1.2.1.1 Definitions.


1.2.2 Unit Unavailability Factors Represented

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

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

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

1.2.2.4 Tabulation of typical unavailability factors.

1.2.3 Purchase and Sale Representation

1.2.3.1. Describe characteristics and level of dependability of transactions.

1.2.4 Retirements

1.2.4.1 Summarize proposed retirements.

1.3 Representation of Interconnected System in Multi-Area Reliability Analysis, including which Areas and regions are considered, interconnection capacities assumed, and how expansion plans of other Areas and regions are considered.
1.4 Modeling of Limited Energy Sources.

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

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

1.6 Modeling of all Resources.

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

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

1.8 Incorporate the reliability impacts of market rules.

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

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

C. Task Force Follow-Up Procedures

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

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

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

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

4. After the completion of the resource adequacy review, report on the Area's plans to the Reliability Coordinating Committee.

Coordinated by: Task Force on Coordination of Planning
Reviewed for Concurrence by: None
Review frequency: Every three years

References: NPCC Glossary of Terms (Document A-7)
Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2)

Guide for Rating Generating Capability (Document B-9)
Guidelines for Requesting Exclusions to Sections 5.1(B) and 6.1(B) of the NPCC
Basic Criteria for Design and Operation of Interconnected Power Systems

Approved by the System Design Coordinating Committee and the Operating Procedure Coordinating Committee on September 28, 1982

Created: September 28, 1982
Revised: February 8, 1994
Revised: June 26, 1998
Revised: November 14, 2002
Revised: August 2, 2006
1.0 Introduction

The Northeast Power Coordinating Council (NPCC) was formed to promote the reliability and efficiency of electric service of the interconnected bulk power system of the members of the Council by extending the coordination of their system design and operations as cited in the NPCC Memorandum of Agreement. Towards that end, the Member Systems of NPCC adopted the Basic Criteria for Design and Operation of Interconnected Power Systems (the Basic Criteria - Document A-2), which establishes the minimum standards for design and operation of the interconnected bulk power system of NPCC. In accordance with those standards, the bulk power system should be designed and operated so as to withstand certain specific contingencies. (Terms in bold typeface are defined in Document A-7, the NPCC Glossary of Terms)

One such contingency, listed under Section 5.1(b), Transmission Design Criteria - Stability Assessment, and under Section 6.1(b), Transmission Operating Criteria - Normal Transfers, involves "simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with normal fault clearing." Although this contingency is normally included in the NPCC Criteria, the Basic Criteria define specific conditions for which a multiple circuit tower situation is an acceptable risk and, therefore, can be excluded.

The Basic Criteria Document A-2 also allows for requests for exclusion from this contingency, on the basis of acceptable risk, for other instances of multi-circuit tower construction. All exclusions must be approved by the Reliability Coordinating Committee (RCC). An acceptance of a request for exclusion is dependent on the successful demonstration that such exclusion is an acceptable risk. These guidelines describe the procedure to be followed and the supporting documentation required when requesting exclusion, and establishes a procedure for periodic review of exclusions of record.

2.0 Documentation

The documentation supporting a request for exclusion to Sections 5.1(b) and 6.1(b) of the Basic Criteria must include the following:

2.1 A description of the facilities involved, including geographic location, length and type of construction, and electrical connections to the rest of the interconnected power system;
2.2 Relevant design information pertinent to the assessment of acceptable risk, which might include: details of the construction of the facilities, geographic or atmospheric conditions, or any other factors that influence the risk of sustaining a multi-circuit contingency;

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

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

2.5 For planned facilities, the estimated frequency of multi-circuit contingencies based on the historical performance of facilities of similar construction located in an area with similar geographic climate and topography.

3.0 Procedure for Obtaining an Exclusion

The following procedure shall be used in obtaining exclusion to Sections 5.1(b) or 6.1(b) of the Basic Criteria:

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

3.2 TFSS shall review the request, verify that the documentation requirements have been met, and determine the acceptability of the request.

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

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

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

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

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

4.0 Periodic Review of Exclusions of Record

Exclusions shall be reviewed within the Area’s transmission reviews as provided in Guidelines for NPCC Area Transmission Reviews (Document B-4). This review shall verify that the basis for each exclusion is still valid. TFSS shall notify TFCP, TFCO, TFSP, and the RCC when an Area’s transmission review has determined exclusion is no longer applicable, and revise the exclusion summary list accordingly.

Coordinated by: Task Force on System Studies

Review frequency: 3 years

References:

Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2)

NPCC Glossary of Terms (Document A-7)

Guidelines for NPCC Area Transmission Reviews (Document B-4)
DRAFT July 17, 2007 Special Protection System Guide

Approved by the Reliability Coordinating Committee on xxxx xx, 2007
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Note:

Terms in bold typeface are defined in the NPCC Glossary of Terms (Document A-7).
1.0 Introduction

This document complements the NPCC Special Protection System Criteria, Document A-11 and provides guidance for consideration in the implementation of the A-11 criteria. The sections of this document are organized in the same order as A-11 to facilitate easy reference between the two documents (but only the main headings.) Some sections by be left blank for this reason.

Close coordination must be maintained among system planning, design, operating, maintenance and protection functions, since both initially and throughout their life cycle, SPSs are a multi-discipline concern.

1.1 This section is intentionally left blank.

1.2 This section is intentionally left blank.

2.0 General Criteria

The general objective for any SPS is to perform its intended function (generator rejection, load rejection, etc.) in a dependable and secure manner. In this context, dependability relates to the degree of certainty that the SPS will operate correctly when required to operate. Security relates to the degree of certainty that the SPS will not operate when not required to operate.

The relative effects on the bulk power system of a failure to operate when desired versus an unintended operation should be weighed carefully in selecting design parameters. For example, the choice of duplication as a means of providing redundancy improves the dependability of the SPS but can also jeopardize security in that it may increase the probability of an unintended operation. This general objective can be met only if the SPS can dependably respond to the specific conditions for which it is intended to operate and differentiate these from other conditions for which action must not take place.

2.1 Issues Affecting Dependability

2.1.1 Redundancy is normally provided by duplication. Some aspects of duplication may be achieved by overarming, which is defined as providing for more corrective action than would be necessary if no failures are considered. The redundancy requirements for an SPS apply only with respect to its response to the conditions it is required to detect.

2.1.2 For an SPS which is composed of multiple protection groups, the risk of simultaneous failure of more than one protection group
because of design deficiencies or equipment failure shall *must* be considered, particularly if identical equipment is used in each protection group. The extent and nature of these failures shall *must* be recognized in the design and operation of the SPS.

2.1.3 Areas of common exposure should be kept to a minimum to reduce the possibility of all groups being disabled by a single event such as fire, excavation, water leakage, and other such incidents.

2.2 Issues Affecting Security

2.2.1 An SPS should be designed to operate only for conditions which require its specific protective or control actions.

2.3 Issues Affecting Dependability and Security

2.3.1 Special Protection Systems should be no more complex than required for any given application.

2.3.2 The components and software used in Special Protection Systems should be of proven quality, as demonstrated either by actual experience or by stringent tests under simulated operating conditions.

2.3.3 Special Protection Systems should be designed to minimize the possibility of component failure or malfunction due to electrical transients and interference or external effects such as vibration, shock and temperature.

2.3.4 Special Protection Systems, including intelligent electronic devices (IEDs) and communication systems used for protection, should comply with applicable industry standards for utility grade protection service. Utility Grade Protection System Equipment are equipment that are suitable for protecting transmission power system elements, that are required to operate reliably, under harsh environments normally found at substations. Utility grade equipment should meet the applicable sections of all or some of the following types of industry standards, to ensure their suitability for such applications:

- IEEE C37.90.1-2002 (oscillatory surge and fast transient)
- IEEE C37.90.1-2002 (service conditions)
- IEC 60255-22-1, 2005 (1 MHz burst, i.e. oscillatory)
- IEC 61000-4-12, 2001 (oscillatory surge)
- IEC 61000-4-4, 2004 (EFT)
2.3.5 Special Protection System circuitry and physical arrangements should be carefully designed so as to
minimize the possibility of incorrect operations due to personnel error.

2.3.6 Special Protection System automatic self-checking facilities should be designed so as not to
degrade the performance of the Special Protection System.

2.3.7 Consideration should be given to the consequences of loss of instrument transformer voltage
inputs to Special Protection Systems.

2.3.8 Consideration should be given to the effect of the means of arming on overall security and
dependability of the SPS. Arming shall have a level of security and dependability
commensurate with the requirements of the SPS.

2.4 Operating Time

Adequate time margin should be provided taking into account study inaccuracies, differences in
equipment, and protection operating times.

2.5 Arming of an SPS

Arming is the selection, which may be external to the SPS, of desired output action based on power system
conditions and recognized contingencies. Arming requirements of an SPS are normally based upon the
results of system studies which take into account recognized contingencies, operating policies/procedures
and current power system load/generation conditions. For a simple SPS, arming may be an on/off function.
An SPS can be armed either automatically or manually.

2.5.1 Automatic arming is implemented without human intervention.

2.5.2 Arming is manual if the recognition, decision or implementation requires human intervention.
Sufficient time with adequate margin for recognition, analysis and the taking of corrective action
shall be allowed.
2.6 Special Protection System Testing and Maintenance

2.6.1 As an SPS may be complex and may interface with other protection systems or control systems, special attention should be placed on ensuring that test devices and test interfaces properly support a clearly defined maintenance strategy in a manner that minimizes the risk of inadvertent operation.

2.6.2 Significant negative combinations should be tested. Negative combinations of input logic are those for which no SPS action occurs. “Significant” refers to combinations which could occur based on realistic system conditions and recognized system contingencies.

2.6.3 Whenever practicable, some of the maintenance testing requirements may be met by analyzing and documenting the detailed performance of the SPS during actual events to demonstrate that the specific testing requirements have been fulfilled. Such an approach can reduce the probability of false operation during maintenance while effectively reducing the extent of planned maintenance.

2.7 Analysis of SPS Performance

2.7.1 Insofar as possible, each active protective function within a protective relay should provide separate target information.

3.0 Equipment and Design Considerations

3.1 This Section is intentionally left blank.

3.2 Voltage Transformers and Potential Devices

3.2.1 Special attention should be given to the physical properties (e.g. resistance to corrosion, moisture, fatigue) of the fuses used in protection voltage circuits.

3.2.2 Voltage transformer installations should be designed with due regard to ferroresonance.

3.3 Logic Systems

3.3.1 The design should recognize the effects of contact races, spurious operation due to battery grounds, dc transients, radio frequency
3.3.2 It is recognized that timing is often critical in logic schemes. Operating times of different devices vary. Known timing differences shall be accounted for in the overall design.

3.4 Microprocessor-Based Equipment

3.4.1 An SPS may incorporate microprocessor-based equipment. Information from this equipment may support other functions such as power system operations. In such cases the software and the interface should be designed so as not to degrade the SPS functions.

3.5 Batteries and Direct Current (dc) Supply

3.5.1 The circuitry between each battery and its first protective device cannot be protected and therefore should be designed so as to minimize the possibility of electrical short circuit.

3.5.2 The design for the regulation of the dc voltage should be such that, under all anticipated charging and loading conditions, voltage within acceptable limits will be supplied to all devices while minimizing ac ripple and voltage transients.

3.6 This Section is intentionally left blank.

3.7 Circuit Breakers

3.7.1 If SPS redundancy is achieved by overarming, dual trip coils are not mandatory.

3.7.2 The indication of the circuit breaker position in Special Protection Systems should be designed to reliably mimic the main contact position.

3.8 Teleprotection

3.8.1 Teleprotection systems should be designed to prevent unwanted operations such as those caused by equipment or personnel.

3.8.2 Two identical teleprotection equipments should not be used in independent protection groups, due to the risk of simultaneous failure of both groups because of design deficiencies or equipment problems.
3.8.3 Areas of common exposure should be kept to a minimum to reduce the possibility of both groups being disabled by a single event such as fire, excavation, water leakage, and other such incidents.

3.8.4 Teleprotection systems should be designed to mitigate the effects of signal interference from other communication sources and to assure adequate signal transmission during bulk power system disturbances.

3.9 Control Cables and Wiring and Ancillary Control Devices

3.9.1 Control cables and wiring and ancillary control devices should be highly dependable and secure. Due consideration should be given to published codes and standards, fire hazards, current-carrying capacity, voltage drop, insulation level, mechanical strength, routing, shielding, grounding and environment.

3.10 Physical Separation / Environment

3.10.1 Means should be employed to maintain environmental conditions that are favorable to the correct performance of Special Protection Systems.

3.11 This Section is intentionally left blank.

Section 3.11 not mapped since these are placeholders only; references to the lead task force and review frequency not mapped since they are already covered in Directory 7.

Prepared by: Task Force on System Protection
Review frequency: 3 years
References: NPCC Glossary of Terms (Document A-7), Special Protection System Criteria (Document A-11)
Guide for Maintenance of Microprocessor Based Protection Relays

Approved by the Reliability Coordinating Committee on July 14, 2004.
Note:

Terms in bold typeface are defined in the *NPCC Glossary of Terms* (Document A-7)
1.0 INTRODUCTION

The use of computer based technology for protective relays has influenced what is considered sufficient for periodic maintenance of microprocessor-based relays. The purpose of this document is to provide guidance for the maintenance of microprocessor-based protective relays as required in Section 2 of NPCC Maintenance Criteria for Bulk Power System Protection, Document A-4 on “verifying operating characteristics”, and in note 1 of Table 1 of Document A-4.

This document applies only to the protective relays. It does not include other protection maintenance that is still required, as outlined in Section 2 of A-4.

This document is not intended to be a maintenance procedure, but rather a guide for member systems to develop their maintenance procedures.

2.0 MICROPROCESSOR-BASED RELAYS

For the purposes of maintenance testing, microprocessor-based relays or Intelligent Electronic Devices (IEDs), can be viewed as being composed of four sections:

1. Analog Input Section,
2. Digital Input/Output Section,
3. Processor Section, and
4. Power Supply Section

Each of the sections can be tested separately.

3.0 ANALOG INPUT SECTION

Measurements of magnitude and angle (calculate where not available directly) of metered values should be compared with known quantities. This supposes that the device uses the same hardware for both protection and metering. If this is not the case, then a calibration test should be conducted to verify the analog inputs.

It is not sufficient to compare the magnitudes as measured by the IED. The input section has filtering with active and passive components, which are vulnerable to change over time and cause changes in the phase characteristics of the channel. Measuring and recording of the phase angle readings is, therefore, required.
4.0 DIGITAL INPUT / OUTPUT SECTION

Each digital input and output that is utilized should be verified for proper functions.

4.1 Inputs

Operation of all used physical inputs should be verified by applying the DC control voltage, and observing associated display, or the computer interface.

4.2 Outputs

Outputs of the IED should be verified either by:

1) Asserting the output element using appropriate relay commands and observe the status of the output relay, or;

2) Where such features are not available, the appropriate output contact can be verified by asserting the associated logic settings that permit contact operation.

5.0 PROCESSOR SECTION

The processor section samples the analog and digital inputs, executes the algorithm and logic, and provides the outputs. It includes program memory, non-volatile memory for settings and volatile memory for sequence of events and oscillography. Processor section also performs self-checking.

All of the downloaded settings and the firmware version should be compared with the official copy of the protection settings to verify that the relay contains the intended settings, and it is working with the intended version of firmware.

6.0 POWER SUPPLY SECTION

Most microprocessor-based IEDs provide measurement of the power supply voltages and/or continuously monitor the power supply voltages, and provide a relay failure alarm if they go out of limits. Where these values are accessible, they should be checked against specified ranges. Alternatively, the alarm should be checked on loss of dc voltage to the power supply.
7.0 INTEGRITY TESTING

This test is intended to verify the integrity of operation of the relay program execution and the processing of the phase voltages and current signals. Verify the correct operation of one of the three-phase protection elements, or a single phase, for a single-phase relay. As an example, for a distance relay, test one of a zone’s A-G, B-G, and C-G elements.

7.1 Multi-Processor Based IEDs

Most relays are designed using a single processor; however, some relay designs use multiple processors. If the processing is divided among several processors, then tests should be conducted to include testing of functions that are executed in the respective processors. The manufacturer and/or manual should be consulted to verify hardware configuration. As an example, if a relay uses two processors, one each for phase and ground elements, then integrity testing should be repeated for phase and ground elements respectively.

Prepared by: Task Force on System Protection
Review frequency: 3 Years
References:
- NPCC Glossary of Terms (Document A-7)
- Maintenance Criteria for Bulk Power System Protection (Document A-4)
This entire document has been mapped to Section 3.0 in Appendix B of Directory 4 – Bulk Power System Protection Criteria.

NPCC

SECURITY GUIDELINES FOR PROTECTION SYSTEM IEDS

Approved by the Reliability Coordinating Committee on July 14, 2004.
Note:

Terms in bold typeface are defined in the *NPCC Glossary of Terms* (Document A-7)
1.0 Introduction

This document establishes the NPCC’s guidelines for the application of remote access to protection system IEDs. It is intended as guidance in meeting the requirements of NPCC Bulk Power System Protection Criteria, Document A-5, Section 2.3.9 and Special Protection System Criteria, Document A-11, Section 2.3.9.

This guideline assumes that appropriate physical measures are in place, and that they meet all applicable standards.

This is not intended to be a procedure, but rather a guide for members systems in designing and applying remote access for protective relays. The need for this guide has arisen due to the current, and wide-scale use of computer based protective relays and associated equipment that have remote access capabilities.

2.0 Scope

This guideline applies to protection group Intelligent Electronic Devices (IEDs), such as relays, programmable logic controllers (PLC), and teleprotection equipment that have remote access capabilities, and are designed and configured for remote access applications.

This guideline is applicable to NPCC bulk power system elements, for which these protection systems are applied.

3.0 Definitions

IED - Intelligent Electronic Device, normally computer based, equipped with digital communication abilities, some examples are protective relays, RTUs, SERs, DFRs, PLCs, data concentrators, telecommunications equipment, and general monitoring equipment.

PLC - Programmable Logic Controller, used to create and implement logical actions and automation.

Remote Access - accessing a device from a remote geographical area via a communications link; once accessed, provides similar local device functionality, at a distance.

Authenticate - to prove to be genuine or is an approved user.

Intrusion - An unauthorized electronic entry into an IED. Access normally provides user access to the functionality of the device.
**Cryptography** – is the study and application of codes and ciphers. Codes or encryption is used to transform data into a form that is not directly usable. Decryption transforms encrypted data using a decryption key back into the original useful form.

**VPN** – Virtual Private Network. It uses encryption to provide a private channel between private networks using a public network as its carrier i.e., two users using the Internet to provide confidentiality, integrity, and authentication.

### 4.0 Governing Principles

The industry has become more reliant on computer technology for power system protection, control, communications, and automation of its power system. Electromechanical and solid-state technologies are being replaced with microprocessor devices, offering, among other functions, local and remote communications access. **Protection system** IEDs are employed to protect, and or operate power system elements. Unauthorized access to an IED could result in interruption of electric service, damage to the power system equipment, major disturbances, or a danger to life and property. **Protection system** IEDs also contain a large amount of information that utility personnel have come to rely on, including telemetry, power system disturbance analysis, fault location, preventive maintenance information, as well as asset condition and optimization data. However, this technology has also created vulnerabilities that are similar to those seen in traditional computer networks. Therefore, the following should be the governing principles of any cyber security program:

- Prevent penetration from cyber attacks.
- Prevent local and remote access to critical cyber assets by non-authorized personnel.
- Monitor cyber assets to detect unauthorized access or attempts to access.
- Limit exposure.

### 5.0 Guidelines

#### 5.1 Authentication

One of the foundations of the cyber security program is controlled, or secure, access. This dictates that some form of user authentication be used. Three common means of authenticating a user’s identity are:

1) Something the user knows, such as passwords, or IP addresses.
2) Something the user has, such as a key, or cryptographic token.

3) Something the user is, such as fingerprints and voiceprints.

At minimum, at least two factors of authentication should be used, e.g., passwords, and a destination – telephone number, or an IP address.

The use of more factors such as encryption, etc. will result in providing more secure authentication. However, most present day and legacy protection system IEDs do not yet support this technology.

Existing equipment often contains some level of security features. At a minimum, they usually provide multi-level passwords. These features should be activated as a first step in security implementation.

5.2 Substation IED Access Points

A list of all substation IEDs that have remote electronic access configured should be compiled and maintained. This list should also include the access method(s) (e.g., dial-in, WAN, etc), the associated phone numbers and/or IP address, passwords, and other pertinent data.

5.3 Approved Remote Access Authorization List

A list of approved users, and the station IEDs they are authorized to access, should be established and maintained. It is vital that all such access information described in Sections 5.2 and 5.3 be classified as confidential, and managed as such.

5.4 Remote Access Configuration

Protection system IEDs should be configured to afford remote access only where needed and approved, and then, only when proper authentication is provided.

5.5 Passwords

Most protection system IEDs offer multiple access levels, each with separate passwords. Normally, a “view” only level is provided which allows a user to extract and or view information only. An alternate access level is provided to allow trained and authorized users to “make” settings and configuration changes, and initiate breaker operations. It is this level of access that is susceptible to an intrusion which could cause the most damage to the power system. Only limited users should have access to this level.
Establish multi-tiered passwords with different privileges for different classes of users.

Default passwords should be changed when remote access is configured.

Make sure that all IEDs have "strong" passwords, i.e., passwords that are not dictionary words, not easily guessable, not blank, or have no password at all. It is recommended that all passwords contain a combination of letters and numbers, and should be at least six characters long.

5.6 Logging/Alarming

When remote connections are used to access the relay beyond "view-only" mode, this should be alarmed and/or logged where possible.

5.7 Controlling Authority Approval

For both local and remote communications, excluding viewing, notification and approval of the Controlling Authority should be required to access in-service **protection system** IEDs. Only authorized users, as per Section 5.3 above, should have remote access capabilities.

5.8 Disable Unused Functions

Often, **protection system** IEDs are put into service with functions that are not used. These functions can create vulnerabilities, and therefore, should be disabled if possible.

6.0 Other Available Higher Level Authentication Factors and Some General Good Practices

As stated in Section 5.1, a minimum of two factors of authentication should be used. However, the use of more factors will result in providing more secure authentication. This Section is intended to provide additional factors and practices that could be implemented where warranted, and where the technology allows.

6.1 For WAN based access systems, implement Virtual Private Network (VPN) technology. VPN technology is also applicable when using ISDN, DSL, and cable.

6.2 Limit, as far as possible, dependence on the public telephone network for substation communications to IEDs. Instead, use secure communications
facilities whenever possible.

6.3 Call back (where the IED device or modem hangs up on the original caller and calls back on a second line to a preconfigured phone number) may be utilized as a portion of an IEDs security to prevent unauthorized access. This security measure added to other security measures will improve the IEDs security. Security can be further enhanced by using a different telephone line for the return call.

6.4 For dial-up modem access, use a hardware lock and key dongle on the analog phone line at each modem and the lock and key combination will act as a gatekeeper. When a call is initiated, the lock at the called modem will verify the existence of a valid key at the calling modem.

6.5 Isolation from the Business/Corporate Network

Isolation of the substation protection system IEDs from the Corporate Network should be provided where possible. Data can be transferred from the substation IEDs to a server connected to a Corporate Network via appropriate firewalls. This practice is warranted because most Corporate Networks are Internet connected and therefore are exposed to external users.

References:

NPCC Bulk Power System Protection Criteria, Document A5

NPCC Special Protection System Criteria, Document A11


NERC Urgent Action Standard 1200 Cyber Security
Monitoring Procedures
for
*Guidelines for Inter-AREA Voltage Control*

Approved by the Task Force on Coordination of Operation on August 18, 1981

Revised:
- May 14, 1985
- February 9, 1989
- November 12, 1992

Reviewed: March 25, 1998
Note:

Terms in bold typeface are defined in the *NPCC Glossary of Terms* (Document A-7).
1.0 Introduction

The Northeast Power Coordinating Council (NPCC) adopted Document B-3, 
*Guidelines for Inter-AREA Voltage Control*, on May 27, 1981. Further, the Task 
Force on Coordination of Operation (TFCO) scope contains the statement:
“Establish monitoring procedures and review performance relative to the 
effectiveness of the operational aspects of NPCC criteria, guidelines and 
procedures... .”

This procedural document establishes TFCO monitoring and reporting 
requirements for Document B-3, as amended to date.

2.0 Basis for Monitoring

2.1 Section 3.1.1 of Document B-3 provides that:

“Each Area shall provide for the supply and control of its reactive 
regulation requirements, including reactive reserve so that applicable 
emergency voltage levels can be maintained following NPCC normal 
criteria contingencies.”

2.2 Section 3.1.2 of Document B-3 provides that:

"Providing that it is feasible to regulate reactive flows on its tie lines, 
each Area may establish a mutually agreed upon normal schedule of 
reactive power flow with adjacent Areas and with neighboring systems 
in other Reliability Councils. This schedule should conform to the 
provisions of the relevant interconnection agreements and may provide for:

- the minimum and maximum voltage at stations at or 
  near terminals of inter-Area tie lines;

- the receipt of reactive flow at one tie point in exchange 
  for delivery at another;

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

- the transfer of reactive power from one Area to 
  another.”
2.3 The TFCO will monitor, every three years, the extent to which these provisions have been met.

2.4 In its reviews of NPCC inter-Area disturbances (see NPCC Document C-2, “Reporting Procedures for System Disturbances”), the TFCO will examine the report for any departure from the NPCC Procedures, and for effectiveness.

3.0 Procedure for Triennial Monitoring and Reporting

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

a) a copy of any new procedures and principles between the reporting Area and adjacent Areas providing detailed application, or,

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

c) a copy of any revisions to the procedures and principles, or understandings currently on file at NPCC, that exist between the reporting Area and adjacent Areas;

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

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

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

Section 3.0 Moved to section 4.0 of Appendix G of Directory #1
Prepared by: Task Force on Coordination of Operation

Review frequency: 3 years

References:  *NPCC Glossary of Terms* (Document A-7),

*Guidelines for Inter-AREA Voltage Control* (Document B-3)

*Reporting Procedures for System Disturbances* (Document C-2)
Procedures for
Shared Activation of
Ten Minute Reserve

This Document, in its entirety, has been mapped to Section 2.0 of Appendix B of Directory 5 – Operating Reserve.

Approved by the Task Force on Coordination of Operation on June 6, 1985

Revised: July 1, 1989
Revised: September 29, 1993
Revised: May 8, 1996
Reviewed: March 25, 1998
Reviewed: January 18, 2000
Reviewed: August 1, 2000
Reviewed: March 12, 2001
Reviewed: May 8, 2001
Reviewed: January 15, 2002
Revised: January 29, 2004
Note: Terms in **bold typeface** are defined in NPCC Document A-07, *Glossary of Terms*. 
1.0 Introduction

NPCC Operating Reserve Criteria (Document A-6) "establishes standard terminology and minimum requirements governing the amount, availability and distribution of operating reserve." This Operating Procedure describes the implementation of inter-Area shared activation of ten-minute reserve.

Objectives

1. To more quickly relieve the initial stress placed on the interconnected transmission system following a large loss of generation or energy purchase.

2. To effect an improvement in reliability achieved by the faster recovery.

3. To assist in achieving compliance with the NERC Disturbance Control Standard (DCS).

4. To sustain assistance for a minimum of ten minutes unless reliability is affected adversely.

5. To provide relief for transmission overloads, low voltage, or other abnormal conditions which might not otherwise be relieved by normal reserve pickup response.

NPCC and PJM require that losses of generation be recovered within fifteen (15) minutes. It is intended that by implementing this procedure, recovery will be achieved faster than it would otherwise have been achieved. This procedure recognizes that a large sudden loss of generation or energy purchase often results in revisions to economy / recallable interchange schedules between several Areas. Joint activation of reserve is intended to ensure that generation or energy purchases that are lost are quickly replaced by having several areas simultaneously loading generation in the few minutes immediately following a loss.

3.0 General

The participating Areas in this procedure to jointly activate reserves are ISO-New England (ISO-NE), New York ISO (NYISO), the Maritimes, and Independent Electricity Market Operator (IMO) in the NPCC, and PJM. The procedure may be implemented whenever a participating Area experiences a sudden loss of generation or energy purchase equal to or greater than 500 MW.
for IMO, ISO-NE, NYISO, and PJM, and 300 MW for the Maritimes. This procedure may be used if two or more resource losses below the reportable event threshold occur within one hour of each other, and the sum of those losses exceeds the reportable event threshold.

Areas are expected to respond to normal condition mismatches of load and generation via their internal generation control or with scheduled purchases.

The NPCC Operating Reserve Criteria (Document A-6) and the Operating Reserve Criteria of all NPCC Areas and of PJM Members are not changed by any of the provisions of this procedure. Each NPCC Area and PJM must continue to maintain operating reserve in accordance with existing requirements. Each Area maintains the ability to recover from its own loss of generation or energy purchase by deploying ten minute reserve within fifteen (15) minutes. In the event there is a shortage of operating reserve within NPCC, available reserve is shared in accordance with the provisions of the NPCC Document C-19, Procedures During Shortages Of Operating Reserve.

The term "Contingent Area" as used in this procedure is defined as the Area experiencing the loss of generation, energy purchase, or one or more conditions stated in objective (5) of section 2.0 above. The term "Assisting Areas" is defined as the other participating Areas. Unless precluded by transmission constraints prevailing at the time of a sudden loss, the following are applicable for the allocation of reserve pick-up to achieve recovery:

1. At least fifty percent (50%) of a loss is allocated to the Contingent Area.

2. The remainder of a loss is normally allocated among the Assisting Areas.

3. No Area should be requested to provide more assistance during a reserve pickup than is required to meet its own largest contingency.

4. Within the constraints noted in items 1-3 above, the NYISO Shift Supervisor assigns allocations to Assisting Areas at the time an applicable contingency or condition occurs.

5. The contingent Area should sustain its request for assistance for a minimum of ten minutes unless reliability is affected adversely.

The procedure provides for the shared recovery of sudden losses of generation or energy purchases by loading and sharing of ten (10) minute reserve and/or revising economy / recallable interchange schedules. Each Area is responsible for the security monitoring of its own system and for the determination of the
amount of assistance that it is able to provide, receive or transfer. Transmission
limits or other internal constraints that preclude the normal implementation of
this procedure are communicated immediately to the NYISO Shift Supervisor.
Whenever normal implementation of the procedure is precluded, the NYISO
notifies Maritimes, ISO-NE, IMO, and PJM.

The NYISO, being centrally located and equipped with telecommunication
facilities to the other participating Areas, acts as the coordinator for this
procedure. NYISO, with due consideration of conditions in other Areas, ensures
that allocations assigned to Assisting Systems are within their response
capability. Within the constraints noted above, the following recovery
guidelines are applicable:

1. Time zero (T+0) is the time immediately following the loss of generation
or energy purchase. Time (T-0) is the time immediately prior to the time
of the loss. NYISO coordinates the time that scheduled changes
resulting from reserve pick-up allocations are to be implemented and
terminated.

2. Assistance by Assisting Areas activating ten (10) minute reserve will
be by interchange schedules that are:

   a. Implemented at a zero time ramp rate immediately following
      allocation notification.

   b. Maintained until the Contingent Area requests a return to
      normal, but not longer than thirty minutes.

   c. Ramped out at a ten-minute ramp rate following communications
      initiated by the Contingent Area which have resulted in mutually
      established interchange schedules. (Ramping procedures for
      second contingencies are set out in (4.6).)

3. The Contingent Area purchases energy in accordance with applicable
policies and agreements covering interchange and emergency
assistance if a deficiency is caused by a withdrawal of assistance when
the limit of 2b above is encountered. Such purchases are independent of
the provisions of this procedure.

4. Assistance provided by Assisting Areas revising economy / recallable
interchange schedules are treated the same as activating ten (10)
minute reserve, and the interchange schedules will be:
a. Implemented at a zero time ramp rate immediately following allocation notification.

b. Maintained in effect until the sudden loss has been fully recovered by the Contingent Area and all assistance by shared activation of reserve has been terminated.

c. Maintained in effect until after actions in item 4b above are completed and until revised interchange schedules are mutually established.

d. Factored into the appropriate hourly economy / recallable interchange schedule.

5. Inadvertent interchange is caused by the implementation of this procedure. Inadvertent will be calculated by multiplying an Assisting Area's allocation by the duration of the assistance in minutes divided by 60. The NPCC Control Performance Working Group (CO-1) will monitor the net inadvertent interchange caused by the use of this procedure on an annual basis and report the results to the NPCC Task Force on Coordinated Operation (TFCO).

4.0 Procedure

4.1 Preliminary Reserve Assignment

On a continuing basis, Maritimes, ISO-NE, IMO, and PJM dispatchers keep the NYISO informed of the largest, single generation or energy purchase contingency on its system and changes thereof.

Information pertaining to an Area's inability to participate, reserve limitations (such as "bottled" reserve or reserves used to deliver economy energy sales), and transmission limitations are reported to Maritimes, ISO-NE, IMO, and PJM by the NYISO Shift Supervisor as those conditions arise.

4.2 Notification of Contingency

Immediately following a sudden loss of generation or energy purchase in the Maritimes, ISO-NE, NYISO, IMO, or PJM, the Contingent Area reports the following information to the NYISO via the interpool direct telephone lines:

- Name of generation or purchase lost.
• Total number of megawatts lost.
• Time that contingency occurred (time zero T+0).
• Any transmission or security problems that affect allocations to Assisting Areas.

4.3 Activation of Reserve

After receiving notification of the contingency, the NYISO Shift Supervisor:

a. Determines each Area's reserve allocation

b. By the direct inter-Area telephone lines, immediately informs each Area of its reserve allocation, the time that the schedule change is effective, and the time that the contingency occurred.

The reserve allocation becomes part of the interchange schedule and is implemented at a zero ramp rate immediately following notification.

4.4 Provision Of Reserve Assistance

The contingent Area should request SAR assistance as soon as possible to provide Assisting Areas with a response window that is as long as possible. Assisting Areas respond as quickly as possible, assuming the same obligation as if the contingency occurred within its Area. Assisting Areas complete a report that documents the Reserve Assistance provided. Instructions and forms for reporting are provided on the NPCC Web Site. To access the Shared Activation of Reserve forms do the following:

Log on to the NPCC Member Site, Select Working Groups then select CO-1. Select Archived Documents. The forms are listed by Areas as SAR.

The Contingent Area initiates immediate action to provide its share of reserve to recover from the generation or energy purchase loss, prepare for the replacement of the reserve assistance assigned to assisting Areas, and proceed to re-establish ten (10) minute reserve at least equal to its next largest contingency.

4.5 Termination of Shared Reserve
As soon as the Contingent Area has provided its reserve allocation, it notifies the NYISO. The NYISO establishes a conference call between all participating Areas and confirms the time that the assistance is terminated. Revised interchange schedules are mutually established as required to ensure that the Assisting Areas properly recall assistance. The Contingent Area replaces the reserve assistance assigned to assisting Areas in a manner consistent with mutually established interchange schedules.

In the event that a Contingent Area is not prepared to replace the remaining portion of its reserve obligation within time zero + 30 minutes, the Contingent Area arranges for additional assistance in accordance with applicable policies and agreements covering interchange and emergency assistance.

In the event that the security of an Assisting Area becomes jeopardized, that Area may cancel all or part of its allocation by notifying the NYISO, which then requests the Contingent Area to pick up the required additional amounts of reserve. The Contingent Area completes a report that documents the recovery provided for the contingency. Instructions and forms for reporting are provided on the NPCC Web Site. To access the Shared Activation of Reserve-Assistance forms do the following:

Log on to the NPCC Member Site.
Select Working Groups then select CO-1. Select Archived Documents.
The forms are listed by Areas as ASAR.

4.6 Subsequent Contingencies

In the event that a subsequent loss of generation or energy purchase occurs during the period when a reserve pick-up is in progress, regardless of the size of the contingency, the second Contingent Area may, at its discretion, withdraw assistance and request the NYISO to reallocate the assistance in accordance with the provisions of this procedure. Upon such notification, the NYISO notifies the first Contingent Area of the amount of withdrawal. Both Contingent Areas immediately enter new interchange schedules that reflect the loss of the assistance, using a zero time ramp.

In the event that the second Contingent Area experiences a contingency that qualifies for shared activation of reserve, the NYISO allocates assistance from the remaining Assisting Areas in accordance with this procedure, upon the request of that Area.
If the second contingency occurs in the Area that has incurred the first contingency, that Area may request additional assistance, in accordance with this procedure, regardless of the size of the contingency.

4.7 Reporting of Shared Activation Reserve Events

The evaluation of Disturbance Control Standard (DCS) compliance for an Area utilizes the NERC Disturbance Recovery Period applicable at the time of the reportable event. The evaluation of compliance for the purpose of determining Area synchronized reserve requirements utilizes a recovery period established by the NPCC.

The reportable event thresholds for the Contingent Area for DCS compliance and adjustments to Area synchronized reserve requirements are specified in NPCC Document C-09, Monitoring Procedures for Operating Reserve Criteria.

4.7.1 To determine compliance for Shared Activation Reserve events a group ACE is calculated from the algebraic summation of the ACE values of all Areas participating in the Shared Activation Reserve procedure. For compliance, the group ACE must cross zero (or return to the pre-contingency group ACE value if the initial group ACE value was negative just prior to the contingency) within the time(s) specified above from the start of the contingency, and, after all schedule changes have been implemented.

4.7.2 A Shared Activation Reserve event exceeding either Reportable Event threshold is a reportable event for all participants in the procedure if the NYISO Shift Supervisor declares implementation of assistance in five minutes or less from the start of the contingency.

4.7.3 A Shared Activation Reserve event exceeding either Reportable Event threshold is a reportable event only for the Contingent Area if the NYISO Shift Supervisor declares implementation of assistance after five minutes of the start of the contingency.

4.7.4 When the group ACE is found to be compliant (per 4.7.1) and all participants shall report (per 4.7.2), all participating Areas are credited with a fully compliant reportable event.

4.7.5 When the group ACE is found to be non-compliant (per 4.7.1) and all participants shall report (per 4.7.2), the computed DCS
compliance factor (and/or adjustment to the Area synchronized reserve requirement) is assigned to all participants that are found to be non-compliant (see 4.7.7 and 4.7.8). Compliant Areas (per 4.7.7 and 4.7.8) are credited with a fully compliant reportable event.

4.7.6 When the group ACE is found to be non-compliant (per 4.7.1), all participants report (per 4.7.2), but all participants are compliant individually (i.e., non-coincident ACE behavior caused the compliance failure), the computed DCS compliance factor (and/or adjustment to the Area synchronized reserve requirement) is assigned to the contingent Area and all Assisting Areas report a fully compliant reportable event.

4.7.7 When the group ACE is found to be non-compliant (per 4.7.1) and all participants report (per 4.7.2), Assisting Areas are compliant when their ACE crosses zero (or returns to the ACE value just prior to its schedule change if it was negative) after the schedule change and within of the time(s) specified above from the start of the contingency.

4.7.8 When the group ACE is found to be non-compliant (per 4.7.1), Contingent Areas are compliant if their ACE crosses zero (or returns to its own pre-contingency ACE value if its own initial ACE value was negative just prior to the contingency) within the time(s) specified above from the start of the contingency and after their schedule change has been implemented.

5.0 Handling of Radial Source Contingencies with Several Areas Receiving Energy

Radial source tie lines crossing Area boundaries (i.e. from HQ to NYISO, ISO-NE, and the Maritimes) may have energy delivered over these lines to more than one Area. Handling of large contingencies on radial sources crossing Area boundaries is described in Appendix A. The methodology presented in Appendix A is generic and should be used for allocation of SAR assistance whenever single, multiple, or overlapping single contingencies occur.

6.0 Radial Source Contingencies with Counterflow Transactions

Coincident with energy transactions delivered out of the Area on radial source tie lines, countervailing transactions may be scheduled simultaneously into the Area. The contingency loss of one of these lines when it is carrying counterflow transactions may be a relatively small net energy loss to the interconnection. However, the size of the individual counterflow transactions could be quite large. The methodology presented in
Appendix A may be used for allocation of SAR assistance whenever radial line
contingencies with counterflow transactions occur. In instances when the net of the
scheduled transactions is less than the **reportable event** threshold, the net interchange
schedules may be ramped out instead of using the SAR procedure. The NYISO Shift
Supervisor and the **Areas** party to the transactions may agree to this action and the
duration of the ramp.
APPENDIX A

Handling of Radial Source Contingencies With Several Areas Receiving Energy

This Appendix describes the handling of large contingencies on radial sources crossing Area boundaries, such as Hydro-Quebec (HQ) to NYISO. At times, these flows may be composed of simultaneous energy deliveries to the directly connected Area and one or more other Areas. It allows for the use of the SAR procedure to allocate the portion of energy not designated for the directly connected receiving Area to other Areas participating in the Shared Activation of Ten Minute Reserve Procedure.

This same methodology can be applied for scenarios with simultaneous imports and exports of energy (counterflow transactions) by one or more Areas on radial sources crossing Area boundaries. The Area losing its ability to deliver energy may receive negative assistance shares from other Areas. In these scenarios, affected Areas should require smaller generation changes to restore ACE while the procedure is in effect and should have a longer period to adjust fully after the contingency. The use of negative assistance is illustrated in examples 5 and 6.

Background

Some of the radial source tie lines crossing Area boundaries from HQ to NYISO, ISO-NE, and the Maritimes have maximum transfer capabilities in excess of the Area’s single largest internal capacity contingency. Energy may be sold over these lines to more than one Area, with transmission service being provided by the Area to which the respective line is directly connected. An Area may limit the flow such that the loss would not exceed an Area’s largest single contingency to maintain Reserve requirements at reasonable levels. Transmission restrictions in other Areas may also limit these flows.

As the delivering entity, HQ has no practical means to provide reserves from its own system in the event of the loss of a tie. When only the directly connected Area receives the delivery, it can treat the energy as an internal source and carry reserve to cover the sudden loss. However, when the energy is delivered to more than one Area, the responsibility for the directly connected Area to carry all of the reserve can become overly burdensome.

Modification to the SAR Procedure

The SAR procedure is modified to allocate portions of the total delivery to Areas in addition to the directly connected Area during an ordinary shared activation of reserve. When the tie line trips, the directly connected Area may choose to activate the SAR procedure, and then each recipient’s share will be allocated to other participants based...
on the principle of mutual assistance, according to share allocation rules in the SAR procedure.

Each Area receiving a portion of energy from the tie line through the directly connected Area will contribute energy to and receive assistance for their portion of the contingency. The Areas supplying this assistance would not have this energy replaced by the directly connected Area when the directly connected Area picks up its reserve to cover its purchase from HQ. Thus, the directly connected Area’s reserve requirement remains the greater of the largest internal contingency or its share of the respective tie line flow.

When MSC 7040 in NYISO, Sandy Pond in ISO-NE, or Eel River in the Maritimes and/or Madawaska in HQ trips, the directly connected Area may initiate the SAR procedure. In order to have each Area receiving energy from HQ prior to the contingency be presented with the correct ACE, all Areas that were receiving energy set their HQ interchange schedules to zero as soon as possible.

Initially, SAR shares would be calculated based on energy scheduled to each Area receiving energy from the tripped element. Initial shares would be allocated to each energy recipient according to the ordinary share allocation rules in the SAR procedure. Thus each energy recipient is assigned one half the energy received initially. An Area would then receive additional allocations to provide assistance to each other Area, until the total amount of the contingency is balanced.

Once the group ACE is restored, the contingent and recipient Areas shall proceed to pick-up the remainder of their respective reserve obligations. A recipient Area shall use its own generation to replace the energy initially received (unless additional alternative arrangements are made) after SAR assistance is withdrawn.

The methodology is iterative. One pass is required to allocate shares for each Area requiring assistance. Key features of the method are demonstrated in the examples below. Maritimes participation is excluded from these examples for simplicity. The values shown are rounded to whole numbers.
Example 1. PJM Buys 400 MW from HQ on MSC 7040, NYISO Buys 1200 MW:

MSC 7040 flow = 1600 MW
HQ – NYISO transaction = 1200 MW
HQ – PJM transaction = 400 MW

<table>
<thead>
<tr>
<th>Area</th>
<th>Initial Share/ Assistance Sought</th>
<th>First Pass</th>
<th>Second Pass</th>
<th>Total Generation Picked Up When SAR Energy Is Supplied Fully</th>
<th>Total Gen. Picked Up After SAR Is Canceled And All ACEs = 0</th>
</tr>
</thead>
<tbody>
<tr>
<td>IMO</td>
<td>200</td>
<td>67</td>
<td>267</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>ISO-NE</td>
<td>200</td>
<td>67</td>
<td>267</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>NYISO</td>
<td>600</td>
<td>67</td>
<td>667</td>
<td>1200</td>
<td></td>
</tr>
<tr>
<td>PJM</td>
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<td>400</td>
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<tr>
<td>Sum</td>
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<td>600</td>
<td>200</td>
<td>1600</td>
<td>1600</td>
</tr>
</tbody>
</table>

Initial Shares – NYISO and PJM are initially assigned one half of their respective purchases from HQ. Consequently, under the ordinary SAR rules, they would be ‘seeking’ assistance for an equal amount. The total assistance sought is 800 MW for the entire contingency amount.

First Pass – NYISO is provided 600 MW of assistance. These shares are allocated equally, 200 MW each, among the other three participants – including PJM.

Second Pass – PJM is provided 200 MW of assistance. These shares are allocated equally, 67 MW each, among the other three participants – including NYISO.

Total Generation Picked up – The additional generation in each Area, after all Areas provided their shares, and the composite NPCC/PJM ACE is restored, and the SAR procedure is about to be canceled, is shown in the next to last column of the table above. The additional generation after the SAR procedure is canceled and each Area returns it ACE to zero is shown in the last column.
The table below summarizes the changes in schedule and ACE from just prior to the contingency, through the cancellation of assistance and full recovery by both Areas losing energy due to the contingency (Note that the HVDC schedule is not shown, as it is modeled as an internal generator for NYISO).

<table>
<thead>
<tr>
<th>Time</th>
<th>IMO Sch</th>
<th>IMO ACE</th>
<th>NE Sch</th>
<th>NE ACE</th>
<th>PJM Sch</th>
<th>PJM ACE</th>
<th>NY Sch</th>
<th>NY ACE</th>
<th>Tot Sch</th>
<th>Tot ACE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre-contingency</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>-400</td>
<td>0</td>
<td>+400</td>
<td>0</td>
<td>0</td>
<td>0</td>
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<tr>
<td>Contingency</td>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>-400</td>
<td>0</td>
<td>+400</td>
<td>1600</td>
<td>0</td>
<td>-1600</td>
</tr>
<tr>
<td>PJM/NY schedule change</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>-400</td>
<td>0</td>
<td>1200</td>
<td>0</td>
</tr>
<tr>
<td>No response, SAR entries</td>
<td>+267</td>
<td>-267</td>
<td>+267</td>
<td>-267</td>
<td>-400</td>
<td>0</td>
<td>-533</td>
<td>-667</td>
<td>0</td>
<td>-1600</td>
</tr>
<tr>
<td>Full response, SAR not canceled</td>
<td>+267</td>
<td>0</td>
<td>+267</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>-533</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>SAR just canceled</td>
<td>0</td>
<td>+267</td>
<td>0</td>
<td>+267</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>-533</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>All get back to ACE = 0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>
Example 2. PJM Buys 1200 MW from HQ on MSC 7040, NYISO Buys 400 MW:

MSC 7040 flow = 1600 MW
HQ – NYISO transaction = 400 MW
HQ – PJM transaction = 1200 MW

<table>
<thead>
<tr>
<th>Area</th>
<th>Initial Share/Assistance Sought</th>
<th>First Pass</th>
<th>Second Pass</th>
<th>Total Generation Picked Up When SAR Energy Is Supplied Fully</th>
<th>Total Gen. Picked Up After SAR Is Canceled And All ACEs = 0</th>
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<tbody>
<tr>
<td>IMO</td>
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<td>200</td>
<td>267</td>
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<td>ISO-NE</td>
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<td></td>
</tr>
<tr>
<td>NYISO</td>
<td>200</td>
<td>200</td>
<td>400</td>
<td>400</td>
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</tr>
<tr>
<td>PJM</td>
<td>600</td>
<td>667</td>
<td>1200</td>
<td>1200</td>
<td>1200</td>
</tr>
<tr>
<td>Sum</td>
<td>800</td>
<td>200</td>
<td>600</td>
<td>1600</td>
<td>1600</td>
</tr>
</tbody>
</table>

Initial Shares – NYISO and PJM are initially assigned one half of their respective purchases from HQ. Consequently, under the ordinary SAR rules, they would be ‘seeking’ assistance for an equal amount. The total assistance sought is 800 MW for the entire contingency amount.

First Pass – NYISO is provided 200 MW of assistance. These shares are allocated equally, 67 MW each, among the other three participants – including PJM.

Second Pass – PJM is provided 600 MW of assistance. These shares are allocated equally, 200 MW each, among the other three participants- including NYISO.

Total Generation Picked up – The additional generation in each Area, after all Areas provided their shares, and the composite NPCC/PJM ACE is restored, is shown in the next to last column of the table above. The additional generation after the SAR procedure is canceled and each Area returns it ACE to zero is shown in the last column.

The table below summarizes the changes in schedule and ACE from just prior to the contingency, through the cancellation of assistance and full recovery by both Areas losing energy due to the contingency (Note that the HVDC schedule is not shown, as it is modeled as an internal generator for NYISO).
<table>
<thead>
<tr>
<th>Time</th>
<th>IMO Sch</th>
<th>IMO ACE</th>
<th>NE Sch</th>
<th>NE ACE</th>
<th>PJM Sch</th>
<th>PJM ACE</th>
<th>NY Sch</th>
<th>NY ACE</th>
<th>Tot Sch</th>
<th>Tot ACE</th>
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<td>0</td>
</tr>
<tr>
<td>Contingency</td>
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<td>0</td>
<td>+1200</td>
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<td>-1600</td>
</tr>
<tr>
<td>PJM/NY schedule change</td>
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<td>+267</td>
<td>-267</td>
<td>-1200</td>
<td>-600 +67</td>
<td>+200 +200</td>
<td>-400</td>
<td>0</td>
<td>-1600</td>
</tr>
<tr>
<td>Full response, SAR not canceled</td>
<td>+267</td>
<td>0</td>
<td>+267</td>
<td>0</td>
<td>-533</td>
<td>0</td>
<td>0</td>
<td>0</td>
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<td>0</td>
</tr>
<tr>
<td>SAR just canceled</td>
<td>0</td>
<td>+267</td>
<td>0</td>
<td>+267</td>
<td>0</td>
<td>-533</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>All get back to ACE = 0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>
Example 3. PJM and NYISO Buy 200 MW from Quebec on Sandy Pond, NE Buys 1200 MW:

| Sandy Pond flow | 1600 MW |
| HQ – NY transaction | 200 MW |
| HQ – NE transaction | 1200 MW |
| HQ – PJM transaction | 200 MW |

<table>
<thead>
<tr>
<th>Area</th>
<th>Initial Share/ Assistance Sought</th>
<th>First Pass</th>
<th>Second Pass</th>
<th>Third Pass</th>
<th>Total Generation Picked Up When SAR Energy Is Supplied Fully</th>
<th>Total Gen. Picked Up After SAR Is Canceled And All ACEs = 0</th>
</tr>
</thead>
<tbody>
<tr>
<td>IMO</td>
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<td>33</td>
<td>267</td>
<td>0</td>
<td>1200</td>
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<td>ISO-NE</td>
<td>600</td>
<td>33</td>
<td>33</td>
<td>667</td>
<td>1200</td>
<td></td>
</tr>
<tr>
<td>NYISO</td>
<td>100</td>
<td>200</td>
<td>33</td>
<td>333</td>
<td>200</td>
<td></td>
</tr>
<tr>
<td>PJM</td>
<td>100</td>
<td>200</td>
<td>33</td>
<td>333</td>
<td>200</td>
<td></td>
</tr>
<tr>
<td>Sum</td>
<td>800</td>
<td>600</td>
<td>100</td>
<td>100</td>
<td>1600</td>
<td>1600</td>
</tr>
</tbody>
</table>

Initial Shares – ISO-NE, NYISO and PJM are initially assigned one half of their respective purchases from HQ. Consequently, under the ordinary SAR rules, they would be ‘seeking’ assistance for an equal amount. The total assistance sought is 800 MW for the entire contingency amount.

First Pass – ISO-NE is provided with 600 MW of assistance. These shares are allocated equally, 200 MW each, among the other three participants.

Second Pass – NYISO is provided 100 MW of assistance. These shares are allocated equally, 33 MW each, among the other three participants.

Third Pass – A third pass is now required to allocate assistance shares to the third component of the contingency. PJM is provided 100 MW of assistance. These shares are allocated equally, 33 MW each, among the other three participants.

Total Generation Picked up – The additional generation in each Area, after all Areas provided their shares, and the composite NPCC/PJM ACE is restored, and the SAR procedure is about to be canceled, is shown in the next to last column of the table above. The additional generation after the SAR procedure is canceled and each Area returns it ACE to zero is shown in the last column.

The table below summarizes the changes in schedule and ACE from just prior to the contingency, through the cancellation of assistance and full recovery by both Areas.
losing energy due to the contingency (Note that the HVDC schedule is not shown, as it is modeled as an internal generator for ISO-NE).

<table>
<thead>
<tr>
<th>Time</th>
<th>IMO Sch</th>
<th>IMO</th>
<th>NE Sch</th>
<th>NE ACE</th>
<th>PJM Sch</th>
<th>PJM ACE</th>
<th>NY Sch</th>
<th>NY ACE</th>
<th>Tot Sch</th>
<th>Tot ACE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre-contingency</td>
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<td>0</td>
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</tr>
<tr>
<td>Contingency</td>
<td>0</td>
<td>0</td>
<td>+400</td>
<td>+1600</td>
<td>-200</td>
<td>0</td>
<td>-200</td>
<td>0</td>
<td>0</td>
<td>-1600</td>
</tr>
<tr>
<td>PJM/NY/NE schedule change</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>-1200</td>
<td>0</td>
<td>-200</td>
<td>0</td>
<td>-200</td>
<td>0</td>
<td>-1600</td>
</tr>
<tr>
<td>No response, SAR entries</td>
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<td>-267</td>
<td>+600</td>
<td>-33=</td>
<td>0</td>
<td>-200</td>
<td>-1600</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Full response, SAR not canceled</td>
<td>+267</td>
<td>0</td>
<td>-533</td>
<td>0</td>
<td>+133</td>
<td>0</td>
<td>+133</td>
<td>0</td>
<td>0</td>
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<tr>
<td>SAR just canceled</td>
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<td>+267</td>
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<td>+133</td>
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<tr>
<td>All get back to ACE = 0</td>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>
**Example 4. ISO-NE, PJM and NYISO Purchase 700 MW each from Quebec on Sandy Pond:**

Sandy Pond flow = 2100 MW  
HQ – NYISO transaction = 700 MW  
HQ – ISONE transaction = 700 MW  
HQ – PJM transaction = 700 MW

<table>
<thead>
<tr>
<th>Area</th>
<th>Initial Share/Assistance Sought</th>
<th>First Pass</th>
<th>Second Pass</th>
<th>Third Pass</th>
<th>Total Generation Picked Up When SAR Energy Is Supplied Fully</th>
<th>Total Gen. Picked Up After SAR Is Canceled And All ACEs = 0</th>
</tr>
</thead>
<tbody>
<tr>
<td>IMO</td>
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<td>117</td>
<td>117</td>
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<td></td>
</tr>
<tr>
<td>ISO-NE</td>
<td>350</td>
<td>117</td>
<td>117</td>
<td>584</td>
<td>700</td>
<td></td>
</tr>
<tr>
<td>NYISO</td>
<td>350</td>
<td>117</td>
<td>117</td>
<td>584</td>
<td>700</td>
<td></td>
</tr>
<tr>
<td>PJM</td>
<td>350</td>
<td>117</td>
<td>117</td>
<td>584</td>
<td>700</td>
<td></td>
</tr>
<tr>
<td>Sum</td>
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<td>350</td>
<td>350</td>
<td>350</td>
<td>2100</td>
<td>2100</td>
</tr>
</tbody>
</table>

**Initial Shares** – ISO-NE, NYISO, and PJM are initially assigned one half of their respective purchases from HQ. Consequently, under the ordinary SAR rules, they would be ‘seeking’ assistance for an equal amount. The total assistance sought is 1050 MW for the entire contingency amount.

**First Pass** – ISO-NE is provided 350 MW of assistance. These shares are allocated equally, 117 MW each, among the other three participants.

**Second Pass** – NYISO is provided 350 MW of assistance. These shares are allocated equally, 117 MW each, among the other three participants.

**Third Pass** – PJM is provided 350 MW of assistance. These shares are allocated equally, 117 MW each, among the other three participants.

**Total Generation Picked up** – The additional generation in each Area after all Areas provided their shares, and the composite NPCC/PJM ACE is restored, and the SAR procedure is about to be canceled, is shown in the next to last column of the table above. The additional generation after the SAR procedure is canceled and each Area returns it ACE to zero is shown in the last column.

The table below summarizes the changes in schedule and ACE from just prior to the contingency, through the cancellation of assistance and full recovery by both Areas.
losing energy due to the contingency (Note that the HVDC schedule is not shown, as it is modeled as an internal generator for ISO-NE).

<table>
<thead>
<tr>
<th>Time</th>
<th>IMO Sch</th>
<th>IMO ACE</th>
<th>NE Sch</th>
<th>NE ACE</th>
<th>PJM Sch</th>
<th>PJM ACE</th>
<th>NY Sch</th>
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<tr>
<td>Contingency</td>
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<td>0</td>
<td>+1400</td>
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<td>-700</td>
<td>0</td>
<td>-700</td>
<td>0</td>
<td>-2100</td>
</tr>
<tr>
<td>PJM/NY/NE schedule change</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>-700</td>
<td>0</td>
<td>-700</td>
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<td>0</td>
<td>-2100</td>
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<td>-117</td>
<td>-583</td>
<td>-117</td>
<td>-583</td>
<td>-117</td>
<td>0</td>
<td>-2100</td>
</tr>
<tr>
<td>Full response, SAR not canceled</td>
<td>+350</td>
<td>0</td>
<td>-117</td>
<td>0</td>
<td>-117</td>
<td>0</td>
<td>-117</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>SAR just canceled</td>
<td>0</td>
<td>+350</td>
<td>0</td>
<td>-117</td>
<td>0</td>
<td>-117</td>
<td>0</td>
<td>-117</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>All get back to ACE = 0</td>
<td>0</td>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>
Radial Source Contingencies With Counterflow Transactions

**Example 5.** Counterflow Transactions on MSC 7040
PJM Exports 400 MW to HQ on MSC 7040, NYISO Imports 1200 MW:

MSC 7040 flow = 800 MW  
HQ – NYISO transaction = 1200 MW  
HQ – PJM transaction = -400 MW (flow is PJM to HQ)

<table>
<thead>
<tr>
<th>Area</th>
<th>Initial Share/ Assistance Sought</th>
<th>First Pass</th>
<th>Second Pass</th>
<th>Total Generation Picked Up When SAR Energy Is Supplied Fully</th>
<th>Total Gen. Picked Up After SAR Is Canceled And All ACEs = 0</th>
</tr>
</thead>
<tbody>
<tr>
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<td>0</td>
</tr>
<tr>
<td>NYISO</td>
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<td>200</td>
<td>-67</td>
<td>533</td>
<td>1200</td>
</tr>
<tr>
<td>PJM</td>
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<tr>
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<td>400</td>
<td>600</td>
<td>-200</td>
<td>400</td>
<td>800</td>
</tr>
</tbody>
</table>

Initial Shares – NYISO and PJM are initially assigned one half of their respective purchase from and delivery to HQ. Consequently, under the ordinary SAR rules, they would be ‘seeking’ assistance for both flows into and out of Quebec. The total net assistance sought is 400 MW for the net contingency amount.

First Pass – NYISO is provided 600 MW of assistance. These shares are allocated equally, 200 MW each, among the other three participants – including PJM.

Second Pass – PJM is provided -200 MW of assistance. These shares are allocated equally, -67 MW each, among the other three participants – including NYISO. These negative shares reduce the net pick-ups required of the assisting Areas.

Total Generation Picked up – The additional generation in each Area, after all Areas provided their shares, and the composite NPCC/PJM ACE is restored, and the SAR procedure is about to be canceled, is shown in the next to last column of the table above. The additional generation after the SAR procedure is canceled and each Area returns it ACE to zero is shown in the last column.
Example 6. ISO-NE Purchase 2000 MW from HQ, PJM and NYISO Deliver 500 MW each to Quebec on Sandy Pond:

Sandy Pond flow = 1000 MW
NYISO - HQ transaction = -500 MW (flow is NY to HQ)
HQ – ISONE transaction = 2000 MW
PJM – HQ transaction = -500 MW (flow is PJM to HQ)

<table>
<thead>
<tr>
<th>Area</th>
<th>Initial Share/ Assistance Sought</th>
<th>First Pass</th>
<th>Second Pass</th>
<th>Third Pass</th>
<th>Total Gen. Picked Up When SAR Energy Is Supplied Fully</th>
<th>Total Gen. Picked Up After SAR Is Canceled And All ACEs = 0</th>
</tr>
</thead>
<tbody>
<tr>
<td>IMO</td>
<td></td>
<td></td>
<td>-83</td>
<td>-83</td>
<td>167</td>
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</tr>
<tr>
<td>ISO-NE</td>
<td>1000</td>
<td>333</td>
<td>-83</td>
<td>-83</td>
<td>834</td>
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</tr>
<tr>
<td>NYISO</td>
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<td>-83</td>
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<td>0</td>
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<tr>
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<td>-83</td>
<td>0</td>
<td>0</td>
<td>-500</td>
</tr>
<tr>
<td>Sum</td>
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<td>1000</td>
<td>-250</td>
<td>-250</td>
<td>1000</td>
<td>1000</td>
</tr>
</tbody>
</table>

Initial Shares – ISO-NE, NYISO and PJM are initially assigned one half of their respective purchase from and delivery to Quebec. Consequently, under the ordinary SAR rules, they would be ‘seeking’ assistance for flows into and out of Quebec. The total assistance sought is 1000 MW for the net contingency amount.

First Pass – ISO-NE is provided 1000 MW of assistance. These shares are allocated equally, 333 MW each, among the other three participants.

Second Pass – NYISO is provided -250 MW of assistance. These shares are allocated equally, -83 MW each, among the other three participants.

Third Pass – PJM is provided -250 MW of assistance. These shares are allocated equally, -83 MW each, among the other three participants.

Total Generation Picked up – The additional generation in each Area after all Areas provided their shares, and the composite NPCC/PJM ACE is restored, and the SAR procedure is about to be canceled, is shown in the next to last column of the table above. The additional generation after the SAR procedure is canceled and each Area returns it ACE to zero is shown in the last column.

Prepared by: Task Force on Coordination of Operation

Review frequency: 3 years
<table>
<thead>
<tr>
<th>References:</th>
<th>Operating Reserve Criteria (Document A-06)</th>
</tr>
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<td></td>
<td>Monitoring Procedures for Operating Reserve Criteria (Document C-09)</td>
</tr>
<tr>
<td></td>
<td>NPCC Glossary of Terms (Document A-07)</td>
</tr>
<tr>
<td></td>
<td>Procedures During Shortages of Operating Reserve (Document C-19)</td>
</tr>
</tbody>
</table>
Operational Planning Coordination

Approved by the Task Force on Coordination of Operation on April 7, 1987

Revised: November 8, 1993
Revised: July 18, 1995
Revised: May 15, 1997
Revised: March 2006 (Appendix D only)
This Procedure is a consolidation of following two former Procedures:

*Operational Planning Coordination* (Document C-13).

*Procedures for Special Communications for Interconnected System Operations - Anticipated Emergency Conditions* (Document C-14).

Document C-13 was first approved by the Task Force on Coordination of Operation on April 7, 1987. It was revised as follows:

- Revised: November 8, 1993
- Revised: July 18, 1995

Document C-14 was approved by the Task Force on Coordination of Operation on January 25, 1988. It was revised as follows:

- Revised: April 3, 1990
- Revised: November 8, 1993
1.0 Introduction

The security coordinators of the NPCC control Areas must have access to the security data specified in this procedure in order to adequately assess the reliability of the NPCC bulk power system. All users of the electric systems, including market participants, must supply such data to the security coordinators of the NPCC Control Areas. 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 Areas or systems as needed to assure reliable operation of the bulk power system. One aspect of this coordination is to ensure that adjacent Areas and neighboring systems are advised on a regular basis of expected operating conditions, including generator, transmission and system protection, including Type I special protection system, outages that may materially reduce the ability of an Area to contribute to the reliable operation of the interconnected system, or to receive and/or render assistance to another Area or neighboring system. To the extent practical, the coordination of outage schedules is desirable in order to limit the severity of such impacts.

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

Participants and other recipients of the information provided by this process must adhere to the NERC Confidentiality Agreement for Electric System Security Data, an appendix to NERC Operating Policy 4.B, Operational Security Information. They must not be engaged in the energy merchant function nor reveal this information to such entities.

2.0 Load/Capacity Forecasts

2.1 Twice yearly, by April 1st and October 1st, respectively, each Area will send to the NPCC Staff an eighteen month Load/Capacity Forecast spreadsheet that shows at least the following weekly projections as defined in Appendix A:
2.1.1 NET CAPACITY

2.1.2 LOAD FORECAST

2.1.3 REQUIRED OPERATING RESERVE

2.1.4 KNOWN UNAVAILABLE CAPACITY

2.1.5 UNPLANNED OUTAGES

2.1.6 NET MARGIN

The NPCC Staff will prepare a composite NPCC assessment and analysis of the eighteen months projection, which will be returned to the Areas in advance of the TFCO’s spring and autumn meetings.

2.2 Each week, each Area will review its weekly net margins, section 2.1.6 above, for the twelve weeks to follow and forward the information to the NPCC Staff for distribution to all Areas.

2.3 On an on-going basis, each Area will review its weekly capacity margins for the remainder of the calendar year and, if a significant deficiency or light load condition is identified, will forward details to other NPCC Areas. A deficiency is deemed to exist when, after recognizing transmission security constraints, allowances for scheduled and forced outages, etc., and after incorporating defined contingency plans, there is insufficient capacity (including contractually firm purchases and sales) to supply expected peak loads and operating reserve requirements. A light load condition is deemed to exist when, after all dispatch actions consistent with internal Area procedures have been implemented, the minimum generation is expected to be greater than the system generation requirement.

In a deficiency or light load condition, or if adverse system operation conditions are expected, any Area may request the NPCC Staff to arrange for a conference call as described in Section 5.2.

3.0 Generator Outage Coordination

3.1 Prior to October 1st of each year, each Area will prepare and distribute an Annual Generator Outage Schedule showing the expected outage dates of all generators with a Net Capacity of 300 MW or more.

Prior to January 1st, and after review by the TFCO, final copies of these schedules will be distributed to all Areas.
3.2 Each Area will update and distribute to the other Areas, and neighboring systems as appropriate, its Annual Generator Outage Schedule in accordance with its own internal procedures and requirements.

4.0 Transmission Outage Coordination

4.1 NPCC Critical Facilities List

4.1.1 The NPCC Critical Facilities List, Appendix D, has two components:

1) the NPCC Transmission Facilities List
2) the list of Type I Special Protection Systems

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

Prior to October 1st of each year, each Area will review and update its Transmission Facilities List and coordinate necessary changes with other appropriate NPCC Areas. Prior to January 1st, and after review by the TFCO, the approved, updated Lists will be distributed to all Areas.

The Task Force on System Protection develops the Special Protection Systems (SPSs) list yearly with input from the Task Force on System Studies. The list is submitted annually to the Reliability Coordination Committee (RCC), and the list of Type I SPSs (SPSs with potential for inter-Area impact, initiated by normal contingencies) will be distributed to all Areas as part of the normal distribution of revised Reference Manual documents.

4.1.2 A temporary reconfiguration of the network may result in one or more facilities not previously listed in Appendix D having inter-Area impact. It is the responsibility of the Area experiencing the condition to notify adjacent Areas or neighboring systems in a timely manner and provide updated status reports during the condition.

4.2 Advance Planning of Transmission Facility Outages
4.2.1 NPCC Document A-2, Basic Criteria for Design and Operation of Interconnected Power Systems, requires that scheduled outages of transmission facilities that affect inter-Area reliability be coordinated sufficiently in advance of the outage to permit the affected Areas to maintain reliability. For the purposes of this procedure, that requirement is extended to all facilities specified on the Critical Facilities List. To meet the requirement, each Area will:

4.2.1.1 submit to NPCC an Annual Transmission Outage Schedule for all facilities listed in Appendix D, prior to October 1 of each year. NPCC will consolidate the Area submittals. The consolidated list will be distributed to the Areas and each Area shall provide a monthly update to the list via the NPCC BBS. The schedule should include all expected transmission outages having a continuous duration of three (3) days or more.

4.2.1.2 carry out, on an on-going basis, advance planning of outages and other system tests that may impact inter-Area operations. As a minimum, all outages to equipment listed in Appendix D should be planned with as much lead-time as practical.

4.3 Notifications of Work

4.3.1 The initiating Area will advise affected Areas of all applications for outages of facilities on the Critical Facilities List, including those which have been planned as per Section 4.2.

Normally, notification for work on facilities covered by this instruction will be submitted to the appropriate Areas at least two (2) working days prior to the time the facility is to be taken out of service. When heavy inter-Area transfers are expected to be required, or at other times when abnormal operating conditions are expected, that notification requirement may be increased to a period of up to seven (7) days.

When an Area receives an outage notification from another Area, prompt attention will be given to the notification and appropriate comments rendered. Analysis will be conducted by each Area in accordance with internal procedures.
4.3.2 An Area will not normally remove from service any transmission facility, which might have a reliability impact on an adjacent Area or neighboring system without prior notification to and appropriate review by that Area or system. However, in the event of an emergency condition, each Area may take action as deemed appropriate; other Areas or systems should be notified immediately.

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

4.3.3 NPCC Document A-2, Basic Criteria for Design and Operation of Interconnected Power Systems, requires that:

“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.”

Each Area will advise the other affected Areas of any protection outage that is associated with an element on the Critical Facilities List and that is expected to last for more than two days.

5.0 Who Shall Provide Data

All users of the electric systems in NPCC, including market participants, must provide the security data specified in this procedure to the security coordinators of the NPCC Control Areas. The security coordinators must have access to such data in order to adequately assess the reliability of the NPCC bulk power system.
6.0 Specific Communications

System operators shall be cognizant of the need to routinely keep their counterparts in adjacent Areas and/or neighboring systems informed concerning their expected operating conditions. Special care shall be taken to ensure that conditions in one system or Area that may have an impact on another system or Area are clearly and timely communicated. Specific communications are conducted as follows:

6.1 Weekly

On each Thursday afternoon, at 14:30, a conference call will be initiated by the NPCC Staff to discuss operations expected during the forthcoming ten-day period (weekend and week). Operations management personnel from the NPCC Areas will participate. In advance of the conference call, each Area or pool will prepare the data specified in Appendices A and B, and forward it to the NPCC Staff by noon of each Thursday. The completed “NPCC Weekly Conference Call Generating/Capacity Worksheet,” Appendix B, together with a list of “Projected Outages of Major Units, 500 MW or Greater” and the list of “Twelve Weeks Projections of Net Margins” will be telecopied to the conference call participants for that day at 13:00 hour.

The NPCC Staff will prepare Conference Call Notes that will be telecopied in draft form to the participants by end of business of the day of the conference call. The final version of the Conference Call Notes with all attachments will be telecopied to the participants and members of the TFCO Friday afternoon (following day). At the same time, the final notes with attachments will also be posted on the NPCC Bulletin Board System in an area only accessible to the participants and the NPCC Security Coordinators.

6.2 Emergency (On Request)

Whenever adverse system operating or weather conditions are expected, any Area may request the NPCC Staff to arrange a conference call to discuss operating details with appropriate operations management personnel from the NPCC Areas and neighboring systems.

6.3 Conditions Requiring Discussion

Items of particular concern that should be discussed during conference calls are described in Appendix C.
Prepared by: Task Force on Coordination of Operation

Review frequency: 3 years

References: Criteria for Review and Approval of Documents (Document A-1)

Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2)

Note: Terms in bold typeface are defined in the glossary located in Document A-1, the Criteria for Review and Approval of Documents

Not mapped since references to related documents are not needed when they are all mapped to the same Directory.
### Appendix A

**LOAD AND CAPACITY TABLE INSTRUCTIONS**

and

**GENERATING CAPACITY WORKSHEET INSTRUCTIONS**

**WEEK BEGINNING**  
(18 months projection)  
The week for which data is to be reported is defined as starting with the Sunday. List each week for the eighteen month projection.

**WEEK BEGINNING**  
(Conference calls)  
The ten day period for which data is to be reported is defined as starting with the Friday following the conference call through the second Sunday.

**INSTALLED CAPACITY**  
Include all available generation at its maximum demonstrated capability for the appropriate seasonal capability period. (Do not include purchases, sales or Independent Power Producers).

**INDEPENDENT POWER PRODUCERS (IPPs)**  
List all IPPs under contract at their maximum demonstrated capability for the appropriate seasonal capability period.

**FIRM PURCHASES**  
Include only those transactions where capacity is delivered. Exclude "energy only" transactions and IPPs.

**FIRM SALES**  
Include only those transactions where capacity is delivered. Exclude "energy only" transactions.

**NET CAPACITY**  
Add Installed Capacity, IPPs and Firm Purchases. Subtract Firm Sales.
**LOAD FORECAST**

The Load Forecast to be entered is defined as that value having an equal probability of being above or below actual demands. Include all load in the service territory. It should not be reduced for Demand Side Management programs or interruptible loads. Reflect any diversity existing within the reporting Area.

The peak load forecast should be the best estimate of the Area’s maximum peak load exposure anticipated for the week reported. The minimum load forecast should be the best estimate of the Area’s minimum load exposure anticipated for the week reported.

**AVAILABLE RESERVE**

Net Capacity minus Load Forecast.

**DEMAND SIDE MANAGEMENT (DSM)**

Include only maximum capability which can be obtained by operator initialization within 4 hours.

**KNOWN UNAVAILABLE CAPACITY**

Include all outages reported on the most recent annual maintenance schedule as well as those deratings or unit outages presently forced out, unavailable, locked in, on extended cold standby or which are anticipated to remain out of service.

**NET RESERVE**

Available Reserve plus DSM minus Known Maintenance.

**REQUIRED OPERATING RESERVE**

The methodology used by each Area in deriving Required Operating Reserve should be included as a footnote to the table.

**GROSS MARGIN**

Net Reserve minus Required Operating Reserve.

**UNPLANNED OUTAGES**

Estimate the amount of generating capacity which will be unavailable. This quantity should be based on historical averages for forced outages and deratings.
**NET MARGIN**

**FORECAST WEATHER**
The Forecast Weather is a brief description of the long range weather forecast anticipated for the entire week. Include the expected range of high and low temperatures, likely precipitation, wind, humidity, etc.

**MINIMUM RESOURCES**
The Minimum Resources are the Area's total minimum resources for the coming week below which operating criteria are violated.

**LIGHT LOAD MARGIN**
The Light Load Margin is the Minimum Load Forecast minus Minimum Resources. A negative number indicates a light load condition. A light load condition is deemed to exist when, after implementing all dispatch actions consistent with internal Area procedures, the minimum load generation is expected to be greater than the minimum system load.
Appendix B

moved to Attachment B of Appendix F of Directory #1.

Appendix B

NPCC WEEKLY CONFERENCE CALL

GENERATING/CAPACITY WORKSHEET
### NPCC Weekly Conference Call
### Generating Capacity Worksheet
(all data in MW)

**Projections for Week Beginning:**

<table>
<thead>
<tr>
<th>New York</th>
<th>Québec</th>
<th>Maritimes</th>
<th>England</th>
<th>Ontario</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

1. **Installed Generating Capacity**
2. **Independent Power Producers**
3. **Firm Purchases**
4. **Firm Sales**
5. **Net Capacity (1 + 2 + 3 - 4)**
   - New York
   - Québec
   - Maritimes
   - England
   - Ontario

6. **Load Forecast (Peak)**
7. **Available Reserve (5 - 6)**
8. **Demand Side Management**
9. **Known Unavailable Capacity ***
10. **Net Reserve (7 + 8 - 9)**
    - New York
    - Québec
    - Maritimes
    - England
    - Ontario
11. **Required Operating Reserve**
12. **Gross Margin (10 - 11)**
    - New York
    - Québec
    - Maritimes
    - England
    - Ontario
13. **Unplanned Outages ***
14. **Net Margin (12 - 13)**
    - New York
    - Québec
    - Maritimes
    - England
    - Ontario
14a. **Reserved Shutdown**
15. **Forecast Weather (F - H/L)**
16. **Load Forecast (minimum)**
17. **Minimum Resources**
18. **Light Load Margin (16 - 17)**

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*Includes Hydro-Québec/New England Phase II energy transactions.
**Hydro-Québec sales include only firmed-up capacity contracts with participants.
***See attached listing for individual generation facilities out of service
Appendix C

CONDITIONS FOR DISCUSSION

Items of particular concern that should be discussed during conference call meetings include, but are not limited to:

- anticipated weather
- load forecast
- largest first and second contingencies
- operating reserve requirements and expected available operating reserve
- capacity deficiencies
- potential fuel shortages or potential supply disruptions which could lead to energy shortfalls
- light load margins
- general and specific voltage conditions throughout each system or Area
- status of short term contracts and other scheduled arrangements, including those that impact on operating reserves
- additional capability available within twelve hours and four hours
- coordination of pumping schedules and any problems that might develop due to light load and minimum generation requirements
- generator outages that may have a significant impact on an adjacent Area or neighboring system
- transmission outages that might have an adverse impact on internal and external energy transfers
- potential need for emergency transfers
- expected transfer limits and limiting elements

A change or anticipated change in the normal operating configuration of the system such as:

- The temporary modification of relay protection schemes so that the usual and customary levels of protection will not be provided;
- the arming of special protection systems not normally armed or the application of abnormal operating procedures
- update of the abnormal status of Type I SPSs forced out of service
This Procedure document in its entirety has been mapped to Sections 1 and 2 of Appendix B in Directory #7 – Special Protection System.

Procedure for NPCC Review of New or Modified Bulk Power System Special Protection Systems (SPS)

Approved by the Task Force on Coordination of Planning on April 5, 1988.

Revised: April 14, 1992
Revised: September 28, 1995
Revised: August 10, 2005
If an entity concludes that a new SPS or a modification of an existing SPS will be required which affects the bulk power system, the following procedure is to be followed to obtain concurrence from NPCC. The procedure is also shown on the attached flow chart. (Terms in bold type face are defined in the NPCC Glossary of Terms (Document A-7).

1. Allowing for sufficient lead time to ensure an orderly review, the entity will notify the chairman of the Task Force on Coordination of Planning (TFCP) of its proposal to install a new SPS or modify an existing SPS. The entity will send copies of the complete notification to TFCO and TFSP. This notification will include statements that describe possible failure modes and whether misoperation, unintended operation or failure of the SPS would have local, inter-company, inter-Area or inter-Regional consequences, when the SPS is planned for service, how long it is expected to remain in service, the specific contingency(s) for which it is designed to operate and whether the SPS will be designed according to the NPCC Bulk Power System Protection Criteria (Document A-5) and the Special Protection System Criteria (Document A-11).

2. If the SPS is expected to have only local consequences, TFCP will request that the Task Force on System Studies (TFSS) and the Task Force on System Protection (TFSP) review the proposal.

   a. TFSP will be notified of the proposed SPS. TFSP will advise TFCP of any concerns.

   b. TFSS will review the analyses that the proposing entity has performed. A presentation may be required from the proposing entity. The purpose of the review will be to confirm that there are no adverse inter-Area or inter-Regional consequences of either a failure of the SPS to operate when and how it is required or an inadvertent or unintended operation of the SPS. If necessary, TFSS will request that the proposing entity conduct additional analyses.

   c. If the TFSS review confirms the SPS has only local consequences, TFSS will send the information to TFCP. If TFCP concurs, they will then notify the proposing entity of NPCC's conclusions that the SPS has only local consequences. TFCP will also notify the Reliability Coordinating Committee (RCC), all the Task Forces, the Compliance Monitoring and...
Assessment Subcommittee (CMAS), the proposing entity and other Member Systems that concurrence has been given to the proposing entity to modify an existing SPS or install a new SPS, at which time, the SPS may be deployed.

d) If the TFSS review concludes that the SPS could have inter-Area or inter-Regional consequences, they will inform the TFCP. Upon receipt of the TFSS conclusion or if TFCP separately determines the SPS could have inter-Area or inter-Regional consequences, TFCP will arrange for an overall NPCC review as detailed in Step 3.

e) TFSS will update the NPCC SPS list/database.

3. If the proposing entity expects the SPS to have inter-Area or inter-Regional consequences, or if the TFSS or TFCP review concludes this to be the case, TFCP will request the Task Force on Coordination of Operation (TFCO), the Task Force on System Protection (TFSP) and TFSS to review it. Each of the Task Forces may require a presentation from the proposing entity.

a) TFSP will confirm the failure modes of the SPS, including actions of back-up protection, and whether or not the SPS complies with NPCC system protection standards. TFSP will review whether the new or modified SPS is in conformance with the NPCC Bulk Power System Protection Criteria (Document A-5) and the Special Protection System Criteria (Document A-11) and forward a summary of their findings to TFCO, TFCP and TFSS. This summary will include a statement as to whether the SPS is in conformance with the Bulk Power System Protection Criteria (Document A-5) and the Special Protection System Criteria (Document A-11) and whether the Task Force has any objections to its modification or installation.

b) TFSS will review the analysis that the proposing entity has performed. The purpose of the review will be to assess the SPS is in conformance with the Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2) and to determine the inter-Area or inter-Regional consequences of either a failure of the SPS to operate when and how it is required or an inadvertent or unintended operation of the SPS. If necessary, TFSS will request that the proposing entity conduct additional studies. When their review is completed, TFSS will forward a summary of their findings to TFCO, TFCP and TFSP. This summary will include a statement as to whether the SPS is in...
conformance with the *Basic Criteria* (A-2) and whether the Task Force has any objections to its modification or installation.

c. TFCO will review the operability of the SPS and forward a summary of their findings to TFCP, TFSS and TFSP. This summary will include a statement as to whether the Task Force has any objections to its modification or installation.

d. TFCP will prepare an overall summary for the RCC. This summary will include the findings of the other Task Forces and whether there are any objections to the modification of the existing SPS or the installation of the new SPS and as a minimum, include the following information:

- Function, i.e. GR-generation rejection etc.
- Identification
- Initiating condition
- Action(s) resulting
- Name of the SPS, and owner, identification number
- Arming, i.e. percentage of time, system conditions for which it’s needed, manual vs. automatic, etc.
- Reason for the installation
- Comments, explanations, such as “temporary until such time…”
- Company, owner
- SPS Number, drawn by NPCC staff
- Current Status, i.e. New, Changed or Removed
- Type Determination
- Determinations of the Task Forces’ analyses
- Consequences of operation, misoperation and failure to operate
- Approximate of load or generation rejected by SPS operation
- Proposed date of deployment
- Proposed date of retirement/deactivation

e. The RCC will review the summary report and act on the proposal to modify an existing SPS or install a new SPS. The RCC may also remand the review of the SPS back to the TFCP if further analyses are determined to be needed.

f. The TFCP will notify the RCC, all the Task Forces, the CMAS, the proposing entity and other member systems of the outcome of the review. Upon NPCC approval of the type and compliance with Criteria, the SPS may be deployed.
g. The TFSS will then update the NPCC SPS list/database.

Prepared by: Task Force on Coordination of Planning

References:

- **Basic Criteria for Design and Operation of Interconnected Power Systems** (Document A-2)
- **Bulk Power System Protection Criteria** (Document A-5)
- **Special Protection System Criteria** (Document A-11)
- **NPCC Glossary of Terms** (Document A-7)
PROCEDURE FOR NPCC REVIEW OF NEW OR MODIFIED BULK POWER SYSTEM SPECIAL PROTECTION SYSTEMS (SPS)

SPS Proposal Submitted to TFCP Chair:

- Inter-Area or Inter-Regional Consequences (Type I or II)

SPS Proposal Notified of the SPS

TFSP Reviews the SPS and Confirms Type

- Only Local consequences (Type III)

TFSS Reviews the SPS and Confirms Type

TFCO Reviews for Operating Impacts

TFSP Reviews the SPS and Failure Modes

TFSS Reviews the SPS and Confirms Type

TFCP Evaluates Reviews and Forwards Recommendation to RCC

TFCP Concur with the Review of Type

- NO

TFCP Initiates Type III Review

TFSP Notified of the SPS

RCC Approves

- NO

Remanded Back to TFCP for Further Review(s) or Information

- YES

TFCP Notifies all Task Forces, CMAS, RCC, Proposing Entity and Member Systems

TFCP Notifies all Task Forces, CMAS, RCC, Proposing Entity and Member Systems

TFSS updates the NPCC SPS List' Database
This Document has been mapped to Directory 2 and Directory 5, as indicated in the Document.

Procedures During Abnormal Operating Conditions

Approved by the Task Force on Coordination of Operation on May 19, 2005
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   3.2 Deficiencies of **Thirty-minute Reserve**
   3.3 Deficiencies of **Ten-minute Reserve** within an **Area**
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   4.1 Scheduling
   4.2 Correction of Transmission Loading if Exceeding Limits
   4.3 Correction of Voltage Conditions
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5.0 Action to Contain an Emergency
   5.1 Action of an Area Experiencing the Problem
   5.2 Action of an Area Causing the Problem
   5.3 Sustained Negative Area Control Error (ACE) Causing a Burden

**Note:**

Terms in bold typeface are defined in the NPCC Glossary of Terms (NPCC Document A-07)
1.0 **Introduction**

The *Emergency Operation Criteria* (NPCC Document A-3) state the essential principles for operations personnel in anticipating and dealing with abnormal operating conditions. This procedure is intended to complement the *Emergency Operation Criteria* (NPCC Document A-3) by providing specific instructions to the system operator during such conditions in an NPCC Area or Areas.

This procedure is also intended to provide specific instructions for the redistribution of operating reserve among the Areas when any Area is forecasting or experiencing an operating reserve deficiency. NPCC Operating Criteria [Emergency Operation Criteria (Document A-3) and Operating Reserve Criteria (Document A-6)] provide objectives for operations personnel in dealing with emergencies and procedures for maintaining operating reserve.

The Areas participating in this procedure are the five NPCC Areas: New England, New York, Ontario, Québec and the Maritimes.

2.0 **Objectives**

2.1 To minimize, when possible, the impact of an evolving event.

2.2 To prevent, contain and control an emergency.

2.3 To alert other Areas when any Area is deficient, or anticipates being deficient, in operating reserve.

2.4 To maximize reliability within NPCC through the sharing of resources when any Area becomes deficient in operating reserve.

2.5 To return to normal operating conditions as soon as possible.

3.0 **Action to Mitigate Operating Reserve Shortages**

Procedures to address shortages of the synchronized portion of ten-minute reserve, thirty-minute reserve, and ten-minute reserve that arise or are foreseen during actual operations are provided in this section. Areas are expected to commit adequate resources during the resource scheduling horizon (e.g., day-ahead Unit Commitment) to meet these requirements.

When an Area becomes deficient or forecasts a deficiency in either the synchronized portion of ten-minute reserve, thirty-minute reserve, and ten-minute reserve, and, the Area cannot meet the corresponding restoration requirements specified in NPCC Document *Operating Reserve Criteria* (A-06), it should.
Inform the senior shift authority in each of the other Areas of the NPCC.

Initiate, or request NPCC Staff to initiate, an NPCC Emergency Preparedness Conference Call, as defined in NPCC Reference Document C-01, NPCC Emergency Preparedness Conference Call Procedures-NPCC Security Conference Call Procedures. These actions should be repeated whenever there is a change in the status of the available reserve with respect to their corresponding restoration requirements specified in NPCC Document Operating Reserve Criteria (A-06). For the sole purpose of these notification actions, the restoration requirements specified in NPCC Document Operating Reserve Criteria (A-06) for ten-minute reserve shall apply to the synchronized portion of ten-minute reserve as well.

Although the procedures in Sections 3.1 through 3.4 are presented in order of increasing severity, shortages of operating reserve during actual operations might not evolve in the presented order.

3.1 Deficiencies of the Synchronized Portion of Ten-minute Reserve

When an Area becomes deficient in the synchronized portion of ten-minute reserve but is not deficient in ten-minute reserve, the deficient Area should consider any or all of the following actions in no implied order to eliminate or minimize the deficiency as soon as practical:

- Activate off-line generation to increase the supply of the synchronized portion of ten-minute reserve.
- Re-dispatch online generation to increase the supply of the synchronized portion of ten-minute reserve.
- Obtain additional resources from outside the Area in accordance with regional and local practices. These resources should not be from the portion of another Area’s operating reserve that is needed to meet the other Area’s operating reserve requirements (current or anticipated).
- Disconnect interruptible loads, which are not contributing to the synchronized portion of ten-minute reserve due to implementation delays in excess of ten minutes, if permitted by market and other applicable rules.
3.2 Deficiencies of Thirty-minute Reserve

If an Area experiences a deficiency in thirty-minute reserve as specified in NPCC Document Operating Reserve Criteria (A-06) and cannot meet its restoration requirements specified therein with its current and planned deployment of resources available to it, the Area should implement any or all of the following actions in no implied order to meet the restoration requirements or to minimize the magnitude and duration of the deficiency:

- Obtain additional resources from outside the Area in accordance with regional and local practices. These additional resources should not be from the portion of another Area’s operating reserve that is needed to meet the other Area’s operating reserve requirements (current or anticipated).

- Recall planned generator and transmission outages that will increase operating reserve or transfer capability, if it can reasonably be expected that additional purchases are available to assist in reducing or eliminating the shortage.

- Recall applicable exports or convert applicable exports to a recallable product and include this energy and/or capacity in its thirty-minute reserve, while respecting Area operating procedures. The source Area of the applicable exports should give proper notification to the sink Area.

- Include interruptible customer load that can be interrupted within thirty minutes in its thirty-minute reserve, if not already included.

- Include voltage reduction that can be implemented within thirty minutes in its thirty-minute reserve, if not already included.

3.3 Deficiencies of Ten-minute Reserve within an Area

If an Area is either currently unable to meet its ten-minute reserve requirement or a deficiency is forecasted, and the Area does not expect to restore its ten-minute reserve within the time specified in NPCC Document Operating Reserve Criteria (A-06) without utilizing either voltage reduction, curtailment of interruptible load that are not part of normal operations, or public appeals, it should:

- Issue the appropriate NERC Energy Emergency Alert level and follow procedures in NERC Standard Emergency Preparedness and Operations EOP-002-0 Attachment I.
Also, the Area should implement any or all of the following actions in no implied order to either restore ten-minute reserve within the time specified in NPCC Document A-06 Operating Reserve Criteria, if possible, or to minimize the magnitude and duration of the persisting deficiency:

- Commit sufficient off-line supply-side resources to create additional ten-minute reserve within the restoration period specified in NPCC Document A-06 Operating Reserve Criteria.

- Recall applicable exports respecting Area operating procedures. The source Area of the applicable exports should give proper notification to the sink Area.

- Obtain additional resources from outside the Area in accordance with regional and local practices. These additional resources should not be from the portion of another Area’s operating reserve that is needed to meet the other Area’s operating reserve requirements (current or anticipated).

- Recall planned generator and transmission outages that will increase operating reserve or transfer capability, if it can reasonably be expected that additional purchases are available to assist in reducing or eliminating the shortage.

- Include interruptible customer load that can be interrupted within ten minutes in its ten-minute reserve, if not already included.

- Include voltage reduction that can be implemented within ten minutes in its ten-minute reserve, if not already included.

- Consider the use of Public Appeals if sufficient time exists to activate them, or if the shortage is expected to last for an extended period.

If an Area remains deficient after implementing all of the applicable actions stated above, the Area should:

- Request that the NPCC Staff survey each Area to complete the information in Appendix A, providing each Area’s first contingency loss, ten-minute reserve and its requirement, thirty-minute reserve and its requirement, and each Area’s Total Transfer Capability (TTC) to and from other Areas.

- Update NPCC Reliability Coordinators with any change to the NERC Energy Emergency Alert Level.
• Coordinate the transfer of emergency energy between Areas so that the deficient Area will ultimately increase the ten-minute reserve available to it.

• Consider requesting that other Areas activate off-line resources if the activation promotes greater transfer of energy to the deficient Area to ultimately increase its ten-minute reserve. Assisting Areas choose how to supply the energy in a manner that is consistent with its own policies and procedures.

3.4 Regional Deficiency of Ten-minute Reserve

When two or more NPCC Areas are deficient in ten-minute reserve and all off line generation that could contribute to alleviating the shortages in the deficient Areas has been activated, then a Regional Reserve Deficiency is declared. During a Regional Reserve Deficiency, the NYISO Shift Supervisor will perform a manual Emergency Regional Reserve Redispatch, allocating Emergency Regional Reserve Dispatch Energy (as energy or capacity) optimally among NPCC Areas, coordinating available resources within or between Areas:

• To provide for maximum transfer capability between the Areas.

• To free bottled energy and/or bottled capacity.

• To allocate the remaining ten-minute reserve among the Areas in a manner which will provide maximum reliability and security considering each Area’s ability to control schedules at its electrical boundaries and the Area’s ability to sustain its first contingency loss.

During a Regional Reserve Deficiency, the NYISO Shift Supervisor will also:

• Issue the appropriate NERC Energy Emergency Alert level and follow procedures in NERC Standard Emergency Preparedness and Operations EOP-002-0 Attachment L.

• Advise all Areas to review their responsibilities should a contingency occur within the NPCC. These responsibilities should be expressed in terms of the acceptable post-contingency transfer levels between all Areas and the maximum time allowed to return transfers to those levels.

4.0 Action to Mitigate Abnormal Operating Conditions
It is recognized that provisions are made in the design of a power system for the satisfactory performance of the system during certain faults or incidents of equipment failure. It is also required that the power system be operated in a prescribed manner to withstand these contingencies.

The following is a summary of methods that can minimize the impact of an event through proper pre-event operation and can result in recovery from abnormal loading or voltage conditions:

4.1 Scheduling

When planning for near term forecast conditions, each Area should develop operating strategies that provide for sufficient generation and transmission to meet the following:

4.1.1 Operating reserve requirements.

4.1.2 Automatic generation control requirement.

4.1.3 Line/tie line loadings within applicable normal operating limits.

4.1.4 Bulk power system voltage within normal limits.

4.1.5 Reactive reserve requirements.

4.2 Correction of Transmission Loading if Exceeding Limits

When an Area is experiencing internal circuit or tie line loading in excess of applicable operating limits, the following steps should be implemented as required and appropriate based on industry-wide and/or local procedures:

4.2.1 Implement local congestion management procedures including but not limited to:

- adjust internal generation,
- transfer load,
- adjust phase angle regulators (phase shifters), and
- redeployment of reactive resources.

4.2.2 Restore out-of-service transmission facilities where possible.

4.2.3 Recall generation and transmission element outages.
4.2.4 Discontinue generation and transmission element commissioning.

4.2.5 Activate/implement voltage reduction.

4.2.6 Utilize the NERC TLR process.

4.2.7 Operate to emergency condition limits.

4.2.8 Establish communication with areas inside and/or outside NPCC and request relief.

4.2.9 All Areas in a position to assist must take any available action, excluding load shedding, to keep loading from exceeding applicable operating limits. Assistance should normally only be requested after similar action has been implemented by the requesting Area or Areas.

4.2.10 The Area or Areas causing the overload (if identifiable) must adjust generation or perform actions up to and including load shedding to keep loading below applicable operating limits.

4.2.11 The Area experiencing the overload must, when effective, open circuits or implement load shedding to return the load on elements to within applicable operating limits.

4.3 Correction of Voltage Conditions

If an Area is experiencing abnormal voltage conditions, it should implement the steps provided in NPCC Document B - 3, Guidelines for Inter-AREA Voltage Control.

If the abnormal voltage is caused by conditions external to NPCC, the following steps should be implemented by the NPCC Area experiencing abnormal voltage conditions as required and appropriate:

4.3.1 Using available voltage and reactive power flow information, determine which system is causing the abnormal voltage or the trend toward abnormal voltage.

4.3.2 Establish communication with the system causing the abnormal voltage.

4.3.3 All NPCC Areas in a position to assist must take any available action to relieve the abnormal voltage condition, excluding the shedding of firm load or opening transmission circuits.
4.3.4 If the action in 4.3.3 above is insufficient, the Area experiencing the difficulty shall promptly take all steps necessary to relieve the abnormal voltage condition, including shedding firm load and/or opening transmission circuits.

4.4 Light Load Conditions

When an Area is anticipating or actually experiencing a Light Load Condition, the Area should:

- Issue the appropriate NERC Energy Emergency Alert level and follow procedures in NERC Standard Emergency Preparedness and Operations EOP-002-0 Attachment I.

To ensure that reliability is maintained and that actual interchange flow is regulated to scheduled values, an Area that is anticipating or actually experiencing a Light Load Condition should consider implementing any of the following applicable steps (that are applicable to all supply-side resources in its Area).

4.4.1 Maximize the benefits to be obtained from schedule adjustments.

4.4.2 If permitted by applicable market rules and/or operating policies, increase load by scheduling available pumped storage facilities in the pumping mode.

4.4.3 Arrange for bilateral inadvertent payback.

4.4.4 If permitted by applicable market rules and/or operating policies, request that an appropriate amount of supply-side resources be reduced to the absolute minimum.

4.4.5 Review all supply-side resource “must-run” requirements. Determine if any may be temporarily removed or if other supply-side resources with lower limits could be brought on in place of normal “must-run” supply-side resources.

4.4.6 Review all supply-side resource “low-limits.” Any supply-side resource’s “low-limit” that can be reduced should be temporarily reduced as low as possible.
4.4.7 Obtain maximum reasonable assistance from Areas within or outside NPCC.

5.0 Action to Contain an Emergency

If preventative measures as outlined under sections 3.0 and/or 4.0 have not been adequate, actions to contain the emergency should then be taken. These actions should apply to both the Area or Areas causing the emergency (if identifiable) and the Area or Areas experiencing the emergency. The following is thus a continuation of the preventative measures implemented in section 3.0 and/or 4.0 above. Sections 5.1 and 5.2 apply to scenarios in which one Area is having an adverse impact on the reliability of another Area.

5.1 Action of an Area Experiencing the Emergency

If an Area is in an emergency because of conditions in another Area, it should implement any of the following actions that removes or lessens the threat to its reliability:

5.1.1 Attempt to identify the specific cause(s) and communicate with relevant Areas. Request assistance if required.

5.1.2 **Shed firm load** or reject generation as appropriate.

5.1.3 Communicate (if time permits) to the adjacent Area that the tie lines will be opened if immediate action is not taken to alleviate the emergency.

5.1.4 Open tie lines to prevent damage to equipment, if necessary.

5.1.5 Issue the appropriate NERC Energy Emergency Alert level and follow procedures in NERC Standard *Emergency Preparedness and Operations EOP-002-0 Attachment 1*.

5.2 Action of an Area Causing the Emergency

If an Area is having an adverse reliability impact in another Area, it is required by NERC and NPCC Operating Policies to respond to requests for assistance from the Area in difficulty that remove or lessen the threat to its reliability, including:

5.2.1 Attempt to identify the specific cause(s) and communicate with relevant Areas. Request assistance if required.

5.2.2 Manually **shed load** until transmission loading and voltage return to acceptable values at all known problem locations.

Sections 5.0 to 5.2 and their sub-sections have been moved to Section 4.0 to 4.2 and their sub-sections in Appendix B of Directory #2.
5.2.3 Open or close tie lines as required.

5.2.4 Issue the appropriate NERC Energy Emergency Alert level and follow procedures in NERC Standard *Emergency Preparedness and Operations EOP-002-0 Attachment 1*.

5.3 Sustained Negative Area Control Error (ACE) Causing A Burden

If an *Area* has a negative ACE that cannot be returned to zero within fifteen minutes with regulation resources presently available and other planned energy resource deployments due to a known and persisting shortage, and the *Area* is burdening other *Areas* or Interconnection frequency, then the *Area* should implement load shedding sufficient to return ACE to zero and perform the following notifications:

- Inform the senior shift authority in each of the other *Areas* of the NPCC.
- Issue the appropriate NERC Energy Emergency Alert level and follow procedures in NERC Standard *Emergency Preparedness and Operations EOP-002-0 Attachment 1*.

Prepared by: NPCC Task Force on Coordination of Operation

References:

- *Emergency Operation Criteria* (NPCC Document A-03)
- *Operating Reserve Criteria* (NPCC Document A-06)
- *NPCC Glossary of Terms* (NPCC Document A-07)
- *Guidelines for Inter-AREA Voltage Control* (NPCC Document B-03)
- *NERC Version 0 Reliability Standards*
### APPENDIX A

#### Reserve Summary

<table>
<thead>
<tr>
<th>Area</th>
<th>First Contingency Loss</th>
<th>Required 30 Minute Reserves</th>
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#### Total Transfer Capability

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Procedure for Reporting and Reviewing
Proposed Protection Systems for the Bulk Power System

This entire procedure has been mapped to Section 4.0 in Appendix B of Directory 4 –Bulk Power System Protection Criteria

Approved by the Task Force on System Protection on February 8, 1994.

Note: Originally approved as Document B-5 by the System Design Coordinating Committee and the Operating Procedure Coordinating Committee on April 13, 1977

B-5   Revised:    July 19, 1983
      Revised:    May 5, 1986
      Revised:    April, 1990

C-22   Converted from B-5: February 8, 1994
       Revised: September 25, 1996
       Revised: April 14, 1999
       Revised: November 14, 2002
       Revised: June 28, 2005
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   5.4 Physical Separation ..............................................................TFSP Form #1-7

   5.5 Breakers ..............................................................TFSP Form #1-7

Note:

Terms in bold typeface are defined in the NPCC Glossary of Terms (Document A-7)
1.0 Introduction and Requirement to Notify

In accordance with the concluding paragraph of the Bulk Power System Protection Criteria (Document A-5) and the Special Protection System Criteria (Document A-11) the member system shall provide the Task Force on System Protection (TFSP) with advance notification of any of its new bulk power system protection facilities, or significant changes in its existing bulk power system protection facilities. The member system shall also provide the TFSP with advance notification of non-member protection facilities as required per NPCC Membership Agreement Article V A(2) (c). Notification will be made to the TFSP early in the engineering design stage.

Sections 1.0 to 5.0 have been mapped to Section 4.0 of Directory #4 with some wording change to reflect Responsible Entity names defined in the Functional Model.

2.0 Additional Requirements for Presentation and Review

2.1 A presentation will be made to the TFSP on new facilities or a modification to an existing facility when requested by either a member system or the TFSP.

2.2 A presentation will be made to the TFSP when the design of the protection facility deviates from the Bulk Power System Protection Criteria (Document A-5).

2.3 A presentation will be made to the TFSP when a member system is in doubt as to whether a design meets the Protection Criteria.

3.0 Data Required for Presentation and Review of Proposed Protection Facilities

3.1 The member system will advise the TFSP of the basic design of the proposed system. The data will be supplied on the attached forms, accompanied by a geographical map, a one-line diagram of all affected areas, and the associated protection and control function diagrams. A physical layout of protection panels and batteries for the purpose of illustrating physical separation will also be included.

3.2 The proposed protection system will be explained with due emphasis on any special conditions or design restrictions existing on the particular power system.
4.0 Procedures for Presentation

4.1 The member system will arrange to have a technical presentation made to the TFSP.

4.2 To facilitate scheduling, the chairman of the TFSP will be notified approximately four months prior to the desired date of presentation.

4.3 Copies of materials to be presented will be distributed to TFSP members 30 days prior to the date of the presentation.

5.0 TFSP Procedures

5.1 The TFSP will review the material presented and develop a position statement concerning the proposed protection system. This statement will indicate one of the following:

5.1.1 The need for additional information to enable the TFSP to reach a decision.

5.1.2 Acceptance of the member statement of conformance to the Protection Criteria.

5.1.3 Acceptance of the submitted proposal.

5.1.4* Conditional acceptance of the submitted proposal.

5.1.5* Rejection of the submitted proposal.

* Position Statements 5.1.4 and 5.1.5 will include an indication of areas of departure from the intent of the protection criteria and suggestions for modifications to bring the protection system into conformance with the NPCC criteria.
5.2 The results of the TFSP review will be documented in the following manner.

5.2.1 A position statement will be included in the minutes of the meeting at which the proposed protection system was reviewed.

5.2.2 If necessary, a letter outlining areas of nonconformance with the NPCC Protection Criteria and recommendations for correction will be submitted to the member system.

5.2.3 The Task Force will maintain a record of all the reviews it has conducted.

Prepared by: Task Force on System Protection

Review frequency: 3 years

References: NPCC Membership Agreement executed as of January 19, 1966 as amended to date

Bulk Power System Protection Criteria (Document A-5)

NPCC Glossary of Terms (Document A-7)

NPCC TFSP Reviewed Facilities List

This part is dropped and nor mapped to Directory 4.
This Procedure document in its entirety has been mapped to Section 3 of Appendix B in Directory #7 – Special Protection System.

Procedure for Reporting and Reviewing Proposed Protection Systems for the Bulk Power System

Approved by the Task Force on System Protection on February 8, 1994.

Note: Originally approved as Document B-5 by the System Design Coordinating Committee and the Operating Procedure Coordinating Committee on April 13, 1977

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Note:

Terms in bold typeface are defined in the NPCC Glossary of Terms (Document A-7)
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2.3 A presentation will be made to the TFSP when a member system is in doubt as to whether a design meets the *Protection Criteria*.

3.0 Data Required for Presentation and Review of Proposed Protection Facilities

3.1 The member system will advise the TFSP of the basic design of the proposed system. The data will be supplied on the attached forms, accompanied by a geographical map, a one-line diagram of all affected areas, and the associated protection and control function diagrams. A physical layout of protection panels and batteries for the purpose of illustrating physical separation will also be included.

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5.1.4* Conditional acceptance of the submitted proposal.

5.1.5* Rejection of the submitted proposal.

* Position Statements 5.1.4 and 5.1.5 will include an indication of areas of departure from the intent of the protection criteria and suggestions for modifications to bring the protection system into conformance with the NPCC criteria.
5.2  The results of the TFSP review will be documented in the following manner.

5.2.1  A position statement will be included in the minutes of the meeting at which the proposed protection system was reviewed.

5.2.2  If necessary, a letter outlining areas of nonconformance with the NPCC Protection Criteria and recommendations for correction will be submitted to the member system.

5.2.3  The Task Force will maintain a record of all the reviews it has conducted.

Prepared by:  Task Force on System Protection

Review frequency: 3 years

References:  NPCC Membership Agreement executed as of January 19, 1966 as amended to date

Bulk Power System Protection Criteria (Document A-5)

NPCC Glossary of Terms (Document A-7)

NPCC TFSP Reviewed Facilities List

Not mapped since references are already covered in Directory 7.
This Document, in its entirety, has been mapped to
Appendix B of Directory #8, with minor modifications as
needed.

All references to Areas of Control Areas have been
changed to the functional model entities (RCs, TOPs,
BAs, etc) or to operating areas or simply areas,
depending on the context of the procedure.

NPCC Inter-Area
Power System Restoration Procedure

Approved by the Task Force on Coordination of Operation on March 14, 2006

Revised: January 11, 2007
# NPCC Inter-Area Power System Restoration Procedure

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H-7  External Power Systems-PJM Communications-Main and Alternate Paths

**Note:** Terms in **bold typeface** are defined in the *NPCC Glossary of Terms* (NPCC Inc. Document A-07).
1.0 Content Summary

The purpose of the “NPCC Inter-Area Power System Restoration Procedure” is to provide guidance and training material to the system operator to manage system restoration events that affect the NPCC Areas and adjoining control areas. This Procedure does not prescribe or supplant the specific restoration plans within each NPCC Area. This Procedure is structured to stipulate restoration actions on the part of an NPCC Area and includes the following broad categories:

- A quick reference of Area restoration plans;
- Area to Area voice communication overview (Appendix H details each Area’s communication links);
- Actions to stabilize remaining electrical islands;
- Assessment of conditions prior to interconnecting;
- Establishing interconnections;
- Actions to remain stable following an interconnection; and
- Training and testing to validate plans.

Although the risk of a complete power system shutdown in North America is minimized by operating to reliability criteria specified by NERC, NPCC and Area authorities, there remains a requirement to be prepared for the worst case scenario. NERC and NPCC require that all Areas maintain viable system restoration plans and restoration capabilities.

The Areas within NPCC have detailed individual restoration plans which meet both NERC and NPCC requirements. These Plans address the possibility of a complete system blackout by calling for the building of a basic minimum power system from designated key facilities. The ultimate goal of this rebuilding process is to reconnect electrical Areas to reestablish a fully interconnected system. At the same time, these Area restoration plans recognize that it is impossible to predict the extent to which each individual control area will be disrupted in a blackout event, nor the specific order in which facilities will become available for service after a system collapse. These partial blackout scenarios have been addressed by the prescription of technical guidelines that can be used to restore the power system following any type of blackout event.

In recognition of the fact that it is impossible to predict the extent of a blackout event nor the ensuing order of resource availability, this document does not attempt to provide specific procedures as to when and where to reconnect NPCC Areas and neighboring areas. Instead, it provides technical guidelines for system operators to reconnect the Areas and provide mutual assistance in a manner that reestablishes interconnected operation in a responsibly expeditious manner.

To preclude compromising the physical and cyber security of critical assets, specific information related to facilities is to be treated as confidential and thus restricted from the public domain. Access to such information is permitted only through controlled mechanisms on a “need to know” basis.
2.0 Restoration Plan Overview Table

The NPCC Area restoration plans are in accordance with all relevant NPCC Criteria and NERC Standards and reflect the best practices of the industry concerning power system restoration. Area restoration plans provide specific direction for recovery from a total or major blackout; and they also provide general guidelines for partial blackouts. Each restoration plan establishes the following major priorities:

- Establish the basic minimum power system within the Area;
- Provide AC supply to nuclear generating units and non-blackstart generating units;
- Restore enough load to stabilize generating units and transmission conditions; and
- Establish Area tie lines.

Table 2-1 below summarizes, at a very high level, the restoration plans of each NPCC Area; Table 2-2 following similarly summarizes the restoration plans of adjoining control areas. Appendices A through G provide a detailed overview of the restoration plans of each of these entities.

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<tr>
<th>Control Area</th>
<th>Control Area Type of Restoration Plan</th>
<th>Primary Priority</th>
<th>Secondary Priority</th>
<th>Priority in Restoring Interconnections</th>
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<tr>
<td>Maritimes Area (New Brunswick System Operator)</td>
<td>Detailed switching plans and duties of the control centers are documented using defined and / or alternate paths.</td>
<td>Restore AC station service to nuclear generating site.</td>
<td>Restore AC supply to station service to all other plants and transmission substations.</td>
<td>At the earliest opportunity in a controlled fashion.</td>
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<tr>
<td>New England Area (ISO-NE)</td>
<td>The ISO-NE and Local Control Centers have a coordinated set of restoration plans. Detailed paths are defined to restore from a complete blackout. Technical guides are prescribed to restore from partial blackouts. Plans identify where and when ties between electrical islands can be made.</td>
<td>Restore AC Station Service to nuclear generation sites.</td>
<td>Restore AC Supply to generating stations, transmission stations and control centers.</td>
<td>Interconnections are made when technically viable. Procedures advocate interconnecting early.</td>
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Table 2-1 NPCC Control Areas (continued)

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<th>Control Area</th>
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<tr>
<td>New York Area (NYISO)</td>
<td>In the event of a complete system shutdown the plan defines a specific switching sequence along with general guidelines to restore the system. In the event of a partial system shutdown only the applicable guidelines and steps are followed.</td>
<td>Restore the basic minimum power system to expedite restoration of AC station service to nuclear generating sites.</td>
<td>Load restoration, but when limited energy is available within the NY system, preference is given to generating station start-up.</td>
<td>High priority given to establishment of tie line operation.</td>
</tr>
<tr>
<td>Ontario Area (IESO)</td>
<td>Strategies for restoration established at time of incident based on sources of potential for restart / blackstart, equipment availability and restoration plan priorities. “Rules of Thumb” developed to guide operators through stages of restoration. IESO directs restoration to create multiple islands simultaneously. There are 8 recognized restoration paths within 4 electrical island strategy diagrams for reference.</td>
<td>Restore AC station service to nuclear generating sites.</td>
<td>Restore AC Supply to Critical Loads (AC &amp; DC station service) for Switchyards, Substations, Generating Stations, Control Centers and interdependent infrastructure (i.e. telecommunication s).</td>
<td>At the earliest opportunity in a controlled fashion.</td>
</tr>
<tr>
<td>Québec Area (HQTE)</td>
<td>The available restoration paths allow for the partition of the main system into five basic minimum power systems.</td>
<td>Restore AC station service to nuclear plant and critical facilities of the five basic minimum power systems.</td>
<td>Restore AC station service to all other facilities.</td>
<td>Emphasis placed on restoring the Gatineau and the Abitibi-Témiscamingue islands from Ontario sources and Gaspé Island from New-Brunswick sources. Otherwise Interconnections are made when technically viable.</td>
</tr>
</tbody>
</table>
Table 2-2 Adjacent Control Areas

<table>
<thead>
<tr>
<th>Control Area</th>
<th>Type of Restoration Plan</th>
<th>Primary Priority</th>
<th>Secondary Priority</th>
<th>Priority in Restoring Interconnections</th>
</tr>
</thead>
<tbody>
<tr>
<td>MISO (Manitoba)</td>
<td>Manitoba uses a defined path approach for system restoration applied over two restoration areas, the Northern collector system and the remainder of the bulk power system. The bulk power system is further subdivided into two areas that are paralleled at predefined locations.</td>
<td>The primary priority for restoration is to restore station service to the valve group on the Southern system.</td>
<td>Secondary priorities are to restore station service to the specified HVdc bipolar pole within time limits and to restore station service to the remainder of plants in the Southern system and in the Northern system to the HVdc collector plants.</td>
<td>There are no specified priority tie lines, but any available tie lines are used as an anchor for the system.</td>
</tr>
<tr>
<td>MISO (Michigan)</td>
<td>The portion of Michigan adjacent to Ontario uses a defined path approach for system restoration. Alternate paths are also defined.</td>
<td>The primary priority for restoration is to restore AC Station service to nuclear plants and to establish a cranking path to provide start up power to all other plants and connect them together.</td>
<td>A secondary priority is to return the City of Detroit to normal power.</td>
<td>It is a priority to reestablish interconnected operation if the tie lines are available. Re establishing tie lines with Ontario is a special consideration due to their proximity to the 120 kV system and plants.</td>
</tr>
<tr>
<td>MISO (Minnesota)</td>
<td>Minnesota uses a defined path approach utilizing the 115 kV system.</td>
<td>The primary priority for restoration is to provide start up power to major generating plants.</td>
<td>The secondary priority is to provide station light and power to remaining stations.</td>
<td>Interconnected operation is reestablished with neighboring jurisdictions as soon as tie lines become available, with tie lines to Manitoba being the priority.</td>
</tr>
<tr>
<td>PJM</td>
<td>Each member company of PJM has its own restoration plan. PJM will coordinate and direct all transmission tie connections to external control areas.</td>
<td>Restore off site power supply to nuclear plants.</td>
<td>Restore AC supply to switchyards, hydroelectric and fossil sites.</td>
<td>The restoration of tie lines will be evaluated as the facilities become available.</td>
</tr>
</tbody>
</table>
3.0 Voice Communications Overview

The ability to communicate is essential to the restoration process. The options for direct voice communications between control centers include the following:

- Public Switched Telephone Networks (PSTN)
- NERC Hot Line
- Cellular Telephones
- Direct Ring Down Circuits
- Utility Owned Voice Channels
- Satellite Telephones

Appendix H-1 shows the various communication media that are available in addition to the Public Switched Telephone Networks. Alternative means of communication to the PSTN can include direct ring down circuits and satellite telephones. All NPCC Areas are Reliability Coordinators, and therefore they are members of the NERC Hotline; the telephones associated with this service operate through the PSTN. Finally, cellular telephones are available for use in all Areas, although they have proven to be unreliable during major events due to excessive phone traffic.

Communication paths directly between NPCC control areas (referred to as primary paths) contain multiple communications media options. In the improbable event that all primary paths between two control areas are interrupted, alternate communication paths, where possible, have been identified and are shown along with the primary paths in Appendices H-2 through H-6. If available, a communication media on the direct or primary path between control areas should be used at all times unless otherwise directed by the control area to use an alternate path for control area to control area coordination.

4.0 Actions to Stabilize Remaining Electrical Islands

4.1 Immediate Actions to Stabilize Conditions Within Electrical Islands

After a significant power system disturbance, electrical islands can result due to the separation and survival of sub-areas from the Interconnection. It is imperative to immediately monitor and assess conditions within these electrical islands and take any warranted actions to stabilize their operation. Actions taken at the control area or local dispatch level may include the switching of reactive control devices, generation dispatch actions, transmission switching or load shedding to secure thermal, voltage or frequency conditions.

4.2 Requirement for Manual Generation Dispatch

If the power system has been severely disrupted, economic dispatch signals may be inaccurately calculated by energy management system software or may be ineffective in their application. Consequently, area control centers may have to suspend use of economic dispatch signals and change over to manual dispatch orders.
4.3 **Tie Line Regulation**

Area control centers should appropriately select flat frequency or tie line bias control to stabilize frequency depending on the status of their tie lines. If a control area is electrically isolated, the flat frequency control mode should be implemented. If two or more control areas have remained connected, combinations of different control modes may have to be explored. Use of flat frequency control by the largest area and tie line bias control by other smaller connected areas could produce the best frequency regulation.

4.4 **Inadvertent Synchronization of Electrical Islands**

Area control centers should recognize that the circuit breakers of transmission circuits that opened during the event, and whose terminals are energized within separate electrical islands, may automatically reclose. This action can be done by automatic synchronism-check relays that were actually installed for a separate purpose, namely the supervision of steady state angles across, and appropriate reclosure of, an open circuit whose terminals are synchronized. The unintentional byproduct of reclosing two electrical islands through synchronism-check relays, whose frequencies and voltages happen to match for a sufficient period of time, may be followed by the immediate trip of the circuit as the islands continue to pull away from each other, and the circuit is too weak to hold them together. Transmission switching authorities within control areas should recognize and address this potential inadvertent automatic reclosing. Furthermore, switching authorities should also consider the potential for manual inadvertent reclosure of circuits between electrical islands and take any necessary actions to preclude or prepare for an inadvertent reclosure. If warranted, system operators should consider blocking the circuit breaker automatic reclosure.

5.0 **Assessment of Conditions Prior to Interconnecting**

When assistance is required from an external control area, communications between control areas must ensure that there is a sufficient level of understanding of:

- existing system conditions after stabilization, and;
- types of assistance that may be sought after synchronization.

The existing system conditions to be assessed include, but are not limited to, the following:

- Load;
- Synchronized Generation;
- Prevailing Voltage and Frequency;
- System Topology;
- System Operating Reserves;
- System Reactive Reserves; and
First Contingency Loss.

The types of assistance may include, but are not limited to, the following:

- Start-up for Generation;
- Frequency Control;
- Tie Line Regulation; and
- System Reserves and Restoration of Loads.

Assessment of these technical considerations will identify the conditions under which a tie line will be established and maintained, reducing the risk of a subsequent separation and the loss of load and/or generation.

These guidelines are offered to guide system operators on technical considerations prior to agreeing to mutually assist a neighbor in an emergency in order to maintain the reliability of their Area (or portion thereof) while enabling such assistance to occur. It is recognized that, in cases where interconnection agreements are in place together with jointly agreed to operating procedures governing mutual assistance in an emergency, their requirements must be met in conjunction with implementing the actions offered in this document.

It must be understood that any assistance agreed to between the Areas is based on acceptable conditions identified by the system operators and agreed to by the system operators.

Once the assessment of conditions prior to interconnecting is completed, and if resources are available, the assisting Area must be prepared to assist to the maximum extent that is reliably possible.

5.1 Inadvertent Synchronization of Electrical Islands

Relaying and reclosing on tie lines should be assessed. While the operation of protection relaying may not be significantly impacted by the presence of an unusually sparse transmission system, system operators may want to disable any automatic reclosing on tie lines, especially if only one tie line is in service, or if only a few remote, low voltage tie lines are in service.

5.2 Tie Line Regulation

Prior to interconnecting, system operators within the Areas on either side of the tie line must determine whether the Areas are already interconnected to any other systems and, if so, what are the interconnection point(s). If synchronization is needed, it will be easier to make frequency adjustments in the smaller system.

Area system operators should also discuss the conditions under which interconnection points may be deliberately opened. Acceptable ranges of
deviations in tie line flows caused by system restoration activities should be established using direction from Section 6, “Mutual Assistance Guidelines.” Restoration activities should strive to follow these guidelines as conditions permit on the system. At the same time, system operators must appreciate the levels of post-contingency tie line flows that could occur (and have to be temporarily sustained) and be ready to delay restoration activities to restore tie line security in response to a contingency.

5.3 Assessment of Reserves Prior to Synchronizing Electrical Islands

Prior to synchronizing electrical islands between control areas, an assessment of the reserves should be made such that the reserves for the new electrical island can be determined and additional reserves be made available if required or an activation plan be adopted for contingency recovery.

Considerations to be assessed prior to synchronizing the electrical islands include, but are not limited to, the following:

- What is the largest single contingency loss?
- Are operating reserves adequate to cover the loss?
- What is the amount of spinning reserve?
- Is a load shedding plan being utilized for reserves?
- If reserves are activated, will any transmission facilities be overloaded?
- If either of the largest contingency losses in the two islands occurs after the combined island is formed, will the interconnection circuit(s) be able to accommodate the resultant power flows within their rating(s)?

It is recommended to place additional interconnection circuits in service once the initial synchronization of the two electrical islands has been accomplished to guard against the contingent loss of the path and provide additional transfer capability between the two control areas.

5.4 Frequency Control

The energy management systems of the NPCC Areas utilize the following control mechanisms to perform interconnected regulation using Automatic Generation Control (AGC) applications:

- Flat Tie Line

  Only the tie line mismatch between scheduled interchange and actual interchange flow is used to determine area control error (ACE).

- Flat Frequency

  Only frequency deviation is used to determine the ACE.
• **Tie Line Bias**

Both frequency deviation and tie line mismatch are used to determine the ACE.

Following a major system disturbance, system operators must determine the status of their respective Automatic Generation Control (AGC) systems, and, if still in service, whether its continuing functioning is desired.

When synchronizing electrical islands between control areas, the smaller island can more readily adjust its frequency to match that of the larger island. Once synchronized, Area control centers should appropriately select flat frequency or tie line bias control to stabilize frequency depending on the status of their tie lines. If two or more control areas have remained connected, or have re-synchronized with each other, combinations of different control modes should be explored. If the above control modes are incorrectly applied, the resulting control actions could actually have a negative impact on the Area.

For instance, if the larger of the control areas was in flat frequency control (as it should be), and the adjacent smaller control area was in flat tie line control, the smaller area would not provide its frequency response as it should for additional contingencies, because the AGC would be controlling to tie line deviations only. Its generators would initially provide some frequency response, but the AGC control would back them down to maintain the tie line on schedule, thereby negating the frequency response contribution of the smaller areas. The use of flat frequency control by the largest Area, and tie line bias control by other smaller connected control areas should produce the best frequency regulation.

The control area system operator must determine if economic dispatch continues to be accurate and/or effective, and if it is determined that it is no longer viable, the system operator should switch to manual dispatch of generation.

The system operator must determine if tie line regulation continues to be accurate and/or effective by determining the following:

- the external Areas(s) to which the control area is connected
- the relative sizes of the Areas(s) to which the control area is connected

If it is determined that the control area remains tied to the massive Eastern Interconnection, the system operator may use normal tie line regulation (tie line bias). However, if only two control areas, or a few control areas, remain tied together, the system operators in the respective control areas should:

- Use flat frequency control in the largest control area
- Use tie line bias control in the smaller control area(s)
5.5 Synchronization or Paralleling of Electrical Islands

It is desirable to synchronize electrical islands between Areas to enhance the stability of both by gaining electrical inertia (generators and motor loads).

Considerations to be assessed prior to synchronizing the electrical islands include, but are not limited to:

- Determining which circuit and circuit breaker to use to synchronize the electrical islands, then apply the guidelines of Section 7.1, “Synchronous Ties”; and
- Estimating the total nominal generator synchronized capacity that will exist in the new combined electrical island after it is synchronized such that the size of single shot load restoration can be determined and agreed to by both Areas as outlined in Section 5.6 following.

If a major system disturbance has completely separated two control areas, the reclosing of their first synchronous interconnection will require synchronization of the two control areas. If the two control areas have already synchronized and established a tie line, before energizing any additional tie lines, system operators must assess the electrical configurations on either side of the tie line under consideration and determine if its reclosing will simply parallel the existing tie lines(s), or if synchronization is required. The principles in section 7.0, “Principles of Restoring Inter-Control Area Ties Lines,” must be followed.

5.6 Provision of External Restoration Service

External restoration service may be provided to an adjacent blacked-out Area. When the assisting Area has strong tie lines remaining with the Eastern Interconnection, load restoration should be limited to the tie capability to the Area to be restored.

When the assisting Area is itself an electrical island, it is necessary to limit the incremental amount of load to be restored to 5% of the total synchronized nominal capacity of the generators in the electrical island. It is important to note that this constraint is based on the nominal synchronized capacity of the generator, representing the inertia of the machine, and not on the actual output of the generator. This is to preclude the resulting frequency and voltage transients from operating any underfrequency load shedding relays, generator underfrequency protection relays or line protection relays.

Caution should be exercised in marginal situations due to cold load pickup, which, when energizing feeder loads, can be two to five times their normal load.

Additional considerations to be assessed prior to providing assistance include, but are not limited to, the following:
5.7 Radially Energize and Restore a Portion of an Adjacent Area’s System

Situations can occur where it is desirable for an Area to supply generating stations, substations and customer load in an adjacent Area. In doing so, caution must be exercised in determining points of separation between the two systems.

Considerations to be assessed prior to providing the assistance include, but are not limited to the following:

- Determine the current load expected to be supplied.
- Determine the expected peak load.
- Determine the generation available.
- Identify real or reactive restrictions (MW and / or MVAR) on the interconnected circuit(s) used to provide the assistance.
- If sourced from an Area’s electrical island, then the considerations of Section 5.6 are applicable.
- Determine the expected duration of this arrangement, if known, until the assisted Area is in a position to return its Area to its normal configuration.

6.0 Establishing Interconnection via Inter-Area Tie Lines

When two systems are to be interconnected, options may be available as to where the interconnection may take place. When these options exist, it is up to the system operator to determine the best location and voltage level to govern the interconnection.

6.1 Synchronous Tie Lines

When synchronizing control areas, the following guidelines should be followed:

Synchronize at locations where:

- Synchronism-check relays and / or manual synchroscopes are available;
- Voltage control resources are at, or in close proximity to, the open points;
- Generation sources are easily manipulated or controlled; and
• Good multi-party communications are available between the personnel directing the synchronization, the system operators controlling the synchronizing breaker, and the system operators controlling the generation facilities on both sides of the open points.

For locations where manual synchronizations are performed, the voltage magnitude of the two systems to be paralleled must be matched as closely as possible. A rule of thumb would be to close the paralleling circuit breaker with not more than a 3% voltage difference between the two islands. After any warranted coarse adjustments are made within each island, the island with the dynamic voltage control device closest to the synchronizing location should perform final voltage adjustments. If possible, the smaller island should have the slightly higher voltage.

The frequency of the two systems must also be closely matched before synchronization. First, the difference in the frequencies of the two systems should be no greater than 20 degrees of relative phase angle rotation per second, or one full synchroscope revolution in 18 seconds. The smaller or incoming island should adjust the frequency and be running at the slightly higher frequency. Finally, the synchroscope phasing should be done as close to the 12 o’clock position as possible, and certainly within ± 20º (approximately ± 3 minutes) of vertical upon the closing of the breaker.

Where available, automatic, programmable synchronism-check relays can be used for synchronizing islands or tie lines if known to be effective. System operators may still have to work to achieve adequate voltage and frequency matches on either side of these automatic relays to allow their operation. Consequently, the required operating conditions for these automatic relays should be known by the Area’s system operators.

6.2 Non-Synchronous Tie Lines

Non-synchronous tie lines, such as HVdc tie lines or variable frequency transformers, can present special concerns during system restoration.

The start-up of older model asynchronous HVdc tie lines must be left until the later stages of system restoration when a strong AC system is in place to support:

• AC / HVdc commutation;
• short circuit requirements; and
• the switching of large MVAR devices.

Newer technology HVdc tie lines and variable frequency transformers may be reliably energized or started even with weak, partially restored AC power systems.
Each Area should develop and maintain the criteria for the restoration of each of their HVdc tie lines and variable frequency transformers. These criteria will take into consideration the capabilities of the equipment to operate effectively in a weakened power system.

Areas should consider situations where non-synchronous tie lines have remained in service following the event. System operators need to determine if these facilities can remain in-service without having a negative impact on the restoration procedures due to their ability to remain stable.

7.0 Considerations to Remain Stable Following Interconnection

Once interconnected, the increase in tie line flow(s) into an island, in response to a generation contingency within the island, is proportional to the relative amounts of generating capacity in each island. The resulting flow can be estimated as follows:

\[
\left\{\text{the MW size of the islanded generation contingency}\right\} \times \left\{\text{the MW size of the island}\right\} \text{ divided by } \left\{\text{the MW size of the combined synchronized system}\right\}
\]

The size is best based on the total capacity of synchronized generation, but this value is hard to determine, and therefore load can be used as an approximate substitute. This information, combined with the considerations addressed in Sections 6.1 through 6.3., will help system operators establish secure flows on tie lines.

7.1 Frequency Considerations

In general, once Areas are tied together and receiving or supplying assistance, system operators should continue restoration efforts in a manner that prevents excessive frequency or voltage deviations. The target for maximum transient frequency swings while receiving assistance is 59.5 to 60.5 Hz. Before performing switching that would introduce load or generation resources, system operators should check and, if needed, take action to ensure that steady state system frequency prior to switching is at a level that will avoid excessive frequency excursions immediately after switching.

7.2 Voltage Considerations

System operators should also discuss desired voltage levels that would be sustainable during the event. The general voltage range for maximum voltage deviation while receiving assistance is 5% of nominal transmission voltages.

7.3 Thermal Considerations

System operators should be aware of three key parameters noted below. The specific amounts for each facility need to be communicated between the
interconnecting Areas. These amounts may be revised as system condition change.

- **Maximum Tie Line Interface Export Loading**

  the maximum tie-line or interface loadings possible based on equipment ratings and operation to provide contingency coverage.

Some control area ties points consist of multiple circuits in parallel and are constrained by the thermal capability of the facilities making up the interface. It should be expected that the tie line interface loading of these interfaces will not exceed:

- The normal continuous rating of any single facility making up the interface; or;
- the appropriate emergency rating of any facility, as a result of the worst contingency impacting the interface.

- **Maximum Tie Line Interface Loading Rate**

  the maximum loading rate of a tie line or interface as allowed by the assisting Area.

  The typical maximum tie line interface loading rates may range from 15 MW per minute to 50 MW per minute, depending on the tie line configuration.

- **Maximum Tie Line Interface Deviation for Step Changes in Load or Generation**

  indicates the maximum step change allowed, from a mutually agreed to schedule flow, on a tie line or interface.

  These deviations are typically the lesser of:

  - 5% of the synchronized capacity, or
  - the cumulative effect of the loading rates of generation within the control area adjacent to the interconnection point.

  The typical maximum tie line interface deviation for step changes in load or generation may range from 15 MW to 100 MW.

8.0 **Training and Exercises**

To maintain the ability of the system operator to respond effectively to a power system emergency, they are certified and trained within NPCC in accordance with all NERC requirements. In addition to operator training conducted within a given NPCC Area,
Exercises serve as a means to demonstrate and sustain this ability. Exercises can also be referred to as drills or simulations. When such activities include system operators working together from more than one NPCC Area, or with jurisdictions external to the NPCC, inter-Area coordination of the emergency response of the system operators is greatly enhanced.

Each individual NPCC Area conducts regular system restoration exercises for their system operators and support staff. These Area exercises focus primarily on procedures specific to the given Area. The NPCC Dispatcher Training Working Group (Working Group CO-02) develops and conducts semiannual training seminars. Exercises conducted as part of the NPCC Working Group CO-02 training program involve system operators from multiple NPCC Areas and therefore can help to also evaluate the coordination of Area restoration plans.

Exercises may include:

- simulated emergency response activities;
- table top simulations;
- exercise participants participating from their normal work headquarters;
- minimal to zero coaching by exercise coordinators; and
- interventions into the conduct of the exercise by exercise coordinators, usually being limited to that necessary to run the exercise and interjecting complications and changed conditions to add credibility and challenge.

Exercises are typically conducted by dedicated exercise coordinators.

For purposes of evaluating the exercise against its objectives, a post exercise assessment, is usually conducted, with feedback gathered to support the creation of an evaluation report to disseminate lessons learned.

The specific requirements for any coordinated inter-Area exercise will be determined by the NPCC Inter-Control Area Restoration Coordination Working Group (Working Group CO-11), with input from the NPCC Dispatcher Training Working Group and relevant system operator critiques. Coordinated inter-Area exercises should be considered as an additional step when an Area is scheduling its own internal restoration exercise in order to foster and sustain inter-Area coordination in performing system restoration.

In general, both Area and NPCC exercises should include experiences and lessons learned from actual restoration events.

Prepared by: NPCC Task Force on Coordination of Operation

Review frequency: 3 years

References: NPCC Glossary of Terms (NPCC Inc. Document A-07)

Emergency Operation Criteria (NPCC Inc. Document A-03)
Appendix A

Maritimes Area Restoration Overview

Objective

This restoration summary is a brief overview of how the Maritimes Area restores the power system following a complete blackout of the Maritimes Area. It does not attempt to cover details of the individual system restoration plans or all the possible blackout scenarios.

Background

The Maritimes Area consists of three Canadian provinces: New Brunswick (NB), Nova Scotia (NS) and Prince Edward Island (PEI), as well as a radially connected portion of the state of Maine {Northern Maine Independent System Administrator (NMISA)}. The New Brunswick System Operator (NBSO) is the Reliability Coordinator for the Maritimes Area, and as such coordinates synchronization between the systems within the Area, and/or with adjacent Areas.

Each entity within the Maritimes Area operates its own electrical grid. NB is connected to NS via two 138 kV lines and one 345 kV line. NB is connected to PEI via two 138 kV cables. Northern Maine ISA is radially connected to NB via two 138 kV lines and three 69 kV lines. There is no direct connection from NS to PEI. In 2004, the total Maritime peak load was approximately 6,000 MW.

Basic Plan

The restoration plan assumes no assistance from adjacent Areas. Each entity within the Maritimes Area has blackstart capability and, therefore, individually establishes their power system according to their detailed switching plans. Each system uses the “open all breaker” method in the beginning of the restoration process. When the power systems are established and stable, the electrical islands will synchronize with each other. The Reliability Coordinator in NB will coordinate the synchronization between NB and NS, NB and PEI, NB and NMISA, as well as the load pick-up in any system from this point on until the systems are fully established. At any time throughout the restoration process, NB may synchronize with an adjacent Area.
Appendix B

New England Area Restoration Overview

Introduction

This procedure addresses restoration of the bulk power system (115 kV and above) after a partial or complete system blackout. Expeditious restoration of the bulk power system depends on independent actions and interactions by NEPOOL Participants, Local Control Centers and the ISO New England Inc. (ISO). Depending on the expanse of the blackout (local area or widespread) numerous Participant and Local Control Center restoration procedures, and this procedure, may need to be implemented simultaneously.

During system restoration, a high priority must be given to the restoration of off-site AC power sources to nuclear generators. Also, technical aspects of system restoration (i.e. unit startups, load pickups, switching surges, voltages, frequency, synchronization of islands, etc.) will be crucial. Recognizing these concerns, this procedure and all Local Control Center and Participant restoration procedures have been developed in a coordinated fashion.

Responsibilities

A. Local Control Centers

1. Determine the extent of the blackout within each Local Control Center and inform the ISO as soon as possible of existing generation and transmission capabilities. (The ISO will determine the extent of the blackout within New England and adjacent power systems and inform the Local Control Centers.)

2. Implement Local Control Center restoration procedures (including necessary coordination with the ISO and adjacent Local Control Centers).

3. Should communications with the ISO fail, 345 kV circuits and inter-Local Control Center and inter-Area tie lines may be energized if prudent to total system restoration, and if communications between the affected parties exist.

B. ISO New England

1. Determine the extent of the blackout throughout New England and adjacent power systems and inform all Local Control Centers of existing generation and transmission capabilities.

2. Implement the ISO restoration procedure (including necessary coordination with the Local Control Centers and adjacent power systems).
3. If the blackout is severe and unit dispatch must be temporarily returned to the Local Control Centers, be prepared to assist the Local Control Centers with the loading function if the Local Control Centers request such assistance.

4. Authorize the closing of inter-Local Control Center and inter-Area transmission lines.

5. Once inter-Local Control Center or inter-Area tie lines are energized, oversee and coordinate load pickups within the interconnected parties.

6. Select priority for start-up power supply to generating stations when the choice is to supply a station in one Local Control Center or a station in another Local Control Center from the same source.

7. Direct load shedding, if necessary, to enable continued reliable restoration of interconnected parties or the closing of inter-Local Control Center or inter-Area tie lines.

8. Monitor bulk power system transmission and generation facilities and, as practical, take action to promote system reliability.

**System Restoration Guidelines**

The following lists guidelines regarding the technical aspects of system restoration that are provided in New England restoration procedures:

A. **Restoration of Off-Site AC Power to Nuclear Generators**
B. **Opening Circuit Breakers and Switches**
C. **Reviewing Load Tap Changer (LTC) Positions**
D. **Generator Start Ups and MW Loading**
E. **Spinning Reserves**
F. **Load Pickups**
G. **Transmission Line Charging**
H. **Voltage Schedules at Generators**
I. **Circuit Energizations**
J. **Synchronization**
K. **Inter-Local Control Center Ties**
L. **Inter-Area Ties**

Recognizing the numerous scenarios of possible system blackouts (the expanse of the blackout and resources available for restoration), knowledge of these guidelines is important. They represent a general-purpose tool for system restoration. More specific guidelines for restoration of the 345 kV system in the event of a complete blackout are also provided in the New England restoration procedures. The specific actions in these guides reflect the general guidelines. Where appropriate, the Local Control Center and the ISO procedures have been coordinated.
Appendix C

New York Area Restoration Overview

Introduction

This procedure establishes the guidelines to be used in the restoration of the New York state power system following a major disturbance. Since the exact extent or nature of the disturbance cannot be predicted, the procedure is presented as a general guide.

- In the event of a complete system shutdown, the Transmission Providers are trained and expected to work from a planned sequence of steps to develop a 345 kV back bone system across the state.

- If a partial shutdown occurs, or if a portion of the NYS Power System becomes isolated, the Transmission Owners shall execute only those steps required to restore the area in which the outage exists.

Prompt restoration of the NYISO total customer load is best accomplished by the restoration of the New York state power system. Although some customer load may be picked up during this procedure to maintain stability and voltage levels, priority must be assigned to the restoration of the major transmission tie lines. Each Transmission Owner may restore load within its area in accordance with its own restoration plan, but load restoration must not delay the restoration of inter-and intra-Area tie lines.

Throughout the restoration process, it is the objective of these procedures that the restored facilities be operated in accordance with the operating criteria of the NY State Reliability Council, the New York ISO, the Northeast Power Coordinating Council and the North American Electric Reliability Council.

Each Transmission Owner is responsible for performing the actions listed below in the substations and facilities within its jurisdiction. As these actions are carried out, the Transmission Owner shall inform the NYISO Shift Supervisor, who is responsible for overall coordination of the restoration procedure.
Appendix D

Ontario Area Restoration Overview

Operational Authority Structure

In accordance with the Ontario Electricity Act of 1998, the Independent Electricity System Operator (IESO) is responsible for managing the reliability of the IESO controlled grid, operating a competitive marketplace for electricity and mitigating the impacts of electricity emergencies on public health and safety.

To accomplish the above, the IESO directs the operation of the IESO controlled grid in accordance with operating agreements with the Ontario Transmission Operators. These agreements identify what transmission system elements are included in the IESO controlled grid and the terms and conditions by which the IESO directs their operation. The IESO has no direct physical control of the devices that comprise the transmission system.

The IESO administers Ontario’s market rules by which market participants are bound by their participation agreements to fulfill specified obligations necessary for reliability.

To operate the interconnections to fulfill its obligations to the Electricity Act, NERC and the Northeast Power Coordinating Council, the IESO has interconnection agreements and associated joint operating procedures with adjacent Reliability Coordinators and Transmission Operators.

To operate the marketplace, the IESO runs an automated dispatch every five minutes. The dispatch algorithm achieves the most economic dispatch in accordance with submitted bids and offers and scheduled transactions given the prevailing electrical security constraints. The dispatch algorithm simultaneously solves for operating reserve.

The IESO can manually dispatch generators by direct voice communication to generator operators when circumstances dictate this be done to manage reliability.

As defined in the NERC functional model, the IESO is a Reliability Coordinator, Transmission Operator, Balancing Authority, Interchange Authority, Transmission Service Provider, Market Operator and Compliance Monitor.

Overview of System Restoration Plan for Ontario

The Ontario Power System Restoration Plan (OPSRP) is structured to address what is needed to enable successful system restoration in four related subject areas:

• Operational;
• Testing;
• Training; and
The primary objective of the Ontario Power System Restoration Plan (OPSRP) is to restore the IESO controlled grid to a secure operating state, to the maximum extent possible, based on the equipment that returns to service after a partial or complete blackout.

The OPSRP priorities are to restore critical station service to the nuclear plants, other generating and transmission facilities, operational control centers and telecommunication installations. This is given top priority to minimize reliance on stored energy systems (batteries, compressed air systems, etc.). Islands containing nuclear and fossil generators are synchronized at the earliest opportunity in an effort to increase the chances of their survival by expediting their return to service.

Since the post-contingency system configuration is not predictable, the plan was designed to be sufficiently flexible to be applicable to the wide range of possible configurations. The OPSRP does not require a step by step restoration of predefined paths; rather, its successful implementation is predicated on strategies, procedures, identified limitations and rules of thumb to overcome them (based on worst case scenarios) that give the system operators guidance for each stage of the restoration. The OPSRP focuses on controlling voltage and frequency deviations to magnitudes that are non-impactive and on reducing the exposure to additional disturbances.

Subsequent to the post disturbance assessment and actions to stabilize any surviving electrical islands, the four stages of system restoration are:

- recovery of generation;
- energizing transmission lines;
- load restoration (initially to lower voltage), and
- synchronizing electrical islands.

By off line study, modeling and engineering analysis, rules of thumb have been developed to guide system operators in overcoming the constraints that are encountered during each of the above four stages of system restoration.

The OPSRP also specifies mandatory independent actions by Restoration Participants to carry out the following:

- maintain the availability of generators post disturbance;
- shed load on underfrequency;
- open circuit breakers that are off potential in preparation for system restoration;
- restore station service at step-down transformer stations; and
- synchronize bypass their units at speed no load (SNL) to sustain their in plant station service, including the switching of any units from condense mode to generate mode.
Should any adjacent interconnected system be stable and secure, or an electrical island within Ontario survive, the IESO controlled grid would be restored using this source of potential. Should Ontario lack a source of restart potential from the aforementioned sources, the OPSRP relies on designated blackstart sites. Certified blackstart service providers must perform an annual test, including the energization of one of the transmission circuits out of the generating station. Their performance is strictly monitored by the IESO for adherence to their ancillary service contract. In addition, it is estimated that, as a minimum, one fossil / nuclear unit at each station is expected to survive, and all available generating sources are expected to aid in the restoration process.

The large size of the IESO-controlled grid led to dividing the system into smaller areas for the purpose of restoration after a complete system shutdown. Depending upon the post-contingency configurations and resources, the plan can be implemented in whole or in part. The IESO can manage the simultaneous creation of, and restoration of, a number of electrical islands. Once formed, these islands are synchronized together, or are synchronized with adjacent areas, in a controlled fashion.

To guide operations staff, the OPSRP contains high level system restoration path diagrams for eight potential paths, and four restoration strategy diagrams for Ontario as a whole in accordance with four large electrical islands. Additionally the IESO has introduced two way communications guidelines to enhance the effectiveness of operational communications with the operations staff of nuclear and fossil generating stations.

**Administration to Sustain Emergency Response Capabilities**

The IESO has implemented all identified opportunities for improvement identified in the various blackout investigations following the power system collapse of August, 2003.

In consideration of the 1998 ice storm and the advent of Ontario’s competitive marketplace in 2002, the associated market rules were strengthened in the area of emergency preparedness. As a consequence, Ontario requires all market participants to file an Emergency Preparedness Plan, and those participants that operate facilities impactive to the restoration process must file and certify a restoration plan attachment. There are currently ninety-six Restoration Participants in Ontario as of April 2005. To maintain Ontario’s collective level of emergency preparedness, the IESO annually conducts large scale exercises supported by localized tabletop drill and training sessions with many of the Restoration Participants.

All OPSRP revisions are achieved with input from all Restoration Participants in Ontario, and the OPSRP fully conforms to NERC and NPCC requirements.

The OPSRP also covers the training requirements for operations staff, testing requirements of facilities, restoration tests (blackstarts) and simulations conducted through tabletop exercises and large scale exercises. All are critical elements to the success of any system restoration plan.
Appendix E

Québec Area Restoration Overview

1.0 Introduction

Every utility takes, in designing and operating its system, all the necessary precautions to limit contingencies leading to a blackout of the system. However, the possibility of such a shutdown still exists, and the utilities must have a plan to restore their system and resume normal operation.

Note: The information contained in this document derives from the system restoration plan of Hydro-Québec TransÉnergie which consists primarily of hydroelectric generation. Therefore some of the information might not be applicable to a different system, and some features particular to fully thermal systems might not have been covered in this text.

2.0 Objective

To allow restoration of the system, safely, in the shortest possible time.

3.0 Methodology

The design of the restoration plan contains the following elements:

• Basic plan;
• Regular follow-up;
• Personnel and material required; and
• Testing of critical components associated with key facilities.

3.1 Basic Plan

The primary priority of the basic restoration plan is the restoration of AC station service to the nuclear plant.

If a blackout occurs, the configuration of the system has to be examined to identify possible restoration paths allowing the partition of the main system into basic minimum power systems (BMPS). A BMPS consists of one or more generating stations, transmission lines and substations. These BMPSs are stand alone and can be restored independently. To restore the total system, the system operator in charge of the restoration process will select one BMPS as the main system upon which all the other BMPSs are to be synchronized. While waiting for that synchronization, as much load as its generation capacity permits continues to be independently restored in each BMPS.
A special case is recognized if a subsystem stays synchronous or can be rapidly synchronized with a neighboring utility, its final integration to the main system will be carried out according to the rules governing exchanges between the two systems, in accordance with the relevant operating agreement.

The selection of the restoration paths is based on practical criteria. The plan is also subject to technical criteria and a number of precautions required for a smooth restoration process. Taking into account these three factors will ensure an optimal restoration procedure having the minimum risk and the shortest duration.

3.2 Follow-up

The following activities are required to ensure the continuous validity of the plan.

3.2.1 Daily Follow-up of the System Configuration

Once the restoration plan is set up, it must be constantly updated to keep track of equipment outages. Some equipment is designated as necessary for the restoration process (i.e., they are within, or directly affect, the restoration path), and a listing is produced and continually updated. If any such equipment is unavailable, an analysis is performed to identify alternate paths or equipment. Some of these substitutes may already be part of the key facilities list, but it is important to analyze each occurrence of simultaneous outages and validate the alternative options accordingly.

Also, an assessment of the yearly maintenance schedule avoids situations that could affect the restoration process.

3.2.2 System Expansion Plan

The impacts of additions and modifications must be assessed and their impact on the restoration procedure thoroughly evaluated.

3.2.3 Presentation of the Plan

The total blackout of a system being an infrequent and sudden event, it is important to keep the operations staff up to date regarding the plan. A formal presentation is scheduled at least once a year with all the operations personnel concerned.
3.3 **Personnel and Material**

To ensure fast and efficient application of the plan, proper logistics is required.

### 3.3.1 Personnel

One **system operator** is selected to be in charge of the restoration process, and his role is clearly defined, along with the role of all other people involved in the process.

**Backup Team**

Each control center, system control center and remote control center must have a multidisciplinary backup team able to solve any problem that might occur during the process. This team includes experts in the following fields: operating procedures, **power system analysis**, electrical apparatus, automatic controls and remote systems, **protective relaying**, telecommunications and computer controlled systems.

A list of the backup team, with the phone numbers, is prepared and continuously updated. It is available at all control centers.

### 3.3.2 Material

**Emergency Procedures**

The plan must be broken down into a set of **emergency procedures** for each **key facility**. These procedures state in a short and precise way the operations that are to be performed to isolate the station (preliminary operations) and then to initiate the restoration process. They do not include technical or administrative information. Their application is compulsory.

Following a blackout, the procedures are to be applied step by step. Any abnormal event preventing the application of one procedure must be reported to the **system operator** in charge. No modification is allowed without his permission, since all these procedures are part of a coordinated plan and depend on operations performed before and after that particular operation.

To facilitate the restoration process, system control and remote system control sets of **emergency procedures** summarize the main steps to follow.
Blackstart Procedures:

These procedures state in a short and precise way the operations to be performed, to start generating units designated as having blackstart capability and used to initiate the BMPS restoration process.

Restoration Process Diagram:

A diagram of the restoration plan, showing all the BMPSs, will assist the on-shift system operator to implement the plan in a step-by-step manner in case of computer deficiencies.

Key facilities and Critical Components Lists:

These lists are continuously kept up to date.

Audio Communication System:

An instantaneous and efficient means for the system operator in charge to communicate with each station.

Automated Functions:

The control centers using computer operating systems use the following functions:

- **Blackout Function**

  To avoid computer overload due to the avalanche of alarms and status changes following the system shutdown, this function should be active only for a very short time and be very selective to allow posting of all the major alarms.

- **Reset Function**

  This function allows the operation, through the remote control center, of any critical circuit breaker in order to speed up the restoration process.

- **Load Restoration Function**

  This function permits the automatic recording of the progress of the load restoration, station by station, for each subsystem.
4.0 Testing of Critical Components Associated With Key Facilities

Testing of critical components associated with key facilities shall be performed at a frequency and for a duration that is sufficient to reasonably ensure that the critical components will function properly when isolated from all power sources not available during a partial or complete system blackout. As a minimum, this frequency and duration of testing is stated in NPCC Document A-03, “Emergency Operation Criteria.”

5.0 Control of the Restoration Process

5.1 Control Centers

As soon as the shutdown of the system is acknowledged, all remote control center system operators and neighboring system operators are notified. Application of the emergency procedures is initiated at once. The corporate emergency response hierarchy is immediately informed of the situation and the following actions are initiated:

- Backup teams are called in;
- Other system operators are called in;
- An operator is dispatched to every unattended key facility;
- An inventory of all unavailable equipment (already out before the blackout and equipment which failed during the event) is set and transmitted to the system operator in charge and to his backup team;
- Information or questions unrelated to the restoration process are not forwarded to the control centers. Only authorized personnel involved in the restoration process are allowed in the control rooms;
- The system operator follows carefully the restoration of the BMPS and checks that all is done according to the plan. Any reported discrepancy is addressed and transmitted to the backup team for analysis. The team then formulates alternate solutions;
- Voltage and frequency profiles are the preferred monitoring indicators to speed up or to slow down the load restoration;
- Synchronization of the different BMPSs is coordinated by the system operator. Load restoration is stopped during synchronization of the BMPS;
- Synchronization of the different subsystems is coordinated by the system operator;
- The next step is to continue load restoration until all the load is back on the system;
- The last step is to resume normal operation and reenergize the tie lines with neighboring utilities.
5.2 Individual Facility

After the blackout has occurred, determine:

- Tripped equipment;
- *Energized* or in service equipment;
- Breakers which have remained closed;
- Unavailable equipment;
- Proceed with emergency procedures; and
- Contact the remote control *system operator* in charge to report any problem.

6.0 Debriefing

As soon as possible after the event a meeting is held to identify any problem, malfunction or difficulty observed during the restoration process.

A final report is prepared to disclose any difficulty encountered and propose corrective actions.
Appendix F
External Power Systems-Midwest ISO Restoration Overview

Operational Authority Structure

The Midwest ISO (MISO) reliability footprint is divided into three regions (Central, East and West). The Central and East regions are handled in the Carmel, Indiana, office, with the West region controlled from the St. Paul, Minnesota, office. Both offices have the same Reliability Coordinator (RC) authority.

The East Region deals with MECS (Michigan Electric Coordinated System), which in turn directs the ITC (International Transmission Company) on operational matters. The MECS is the Balancing Authority, and the ITC is the Transmission Owner.

The West Region deals with Minnesota Power and Manitoba Hydro, both of which are Balancing Authorities and Transmission Owners.

The MISO dispatches all generation for its member companies, and it has functional control of their operations, meaning that the MISO has the authority to direct actions to be taken by the Balancing Authorities and / or Transmission Owners. The MISO does not have the capability to physically control equipment on the system (this is done by the Transmission Owner). The MISO approves transmission access request, and the MISO scheduling coordinates schedules on a footprint wide basis.

Emergency Preparedness

The MISO reliability coordinators and real-time operational staff handle system emergencies according to NERC guidelines and internal MISO procedures. Information for dissemination to public entities comes from the MISO real-time management; this is then provide to the MISO public relations department which issues the information for public consumption.

System Restoration Summary

The MISO has detailed coordinated restoration plans. These are reviewed yearly with participation from the MISO member companies. MISO uses a sub-regional structure and philosophy to coordinate and plan for restoration. There are nine identified sub-regions in the MISO footprint that are geographical and electrical in nature. This allows for response to be flexible depending on where the restoration needs exist. The MISO system restoration plan contains all pertinent infrastructure information involved in restoration, including blackstart unit locations, synchroscope locations, critical paths, critical loads, etc. Given that the location or magnitude of a system separation cannot be predicted, the MISO plan and structure give it the ability to respond to any given restoration situation. The MISO also has developed an interconnection checklist to ensure island stability and enhance successful synchronizing when tying islands together. The MISO also has data collection forms that are utilized during restoration to
allow for quick assessment and dissemination of information during actual restoration events.

Plans are practiced yearly through exercises to assess the response plan, Reliability Coordinator action, Balancing Authority system operator action and Transmission Operator reaction to a system separation event. Past exercises have focused on operator understanding of the restoration plan, concepts of restoration, testing all aspects of communication protocols (Reliability Coordinator to Reliability Coordinator, Reliability Coordinator to control area, control area to control area, etc.), island operation, and interconnections.
Appendix G

External Power Systems-PJM Restoration Overview

In the PJM RTO, during the initial stages of a restoration, each Load Serving Entity is responsible for restoring its own customer load with internal generation or through coordinated efforts with other Transmission / Generation Owner. After a subsystem is stabilized, requests from neighboring entities for cranking power are a higher priority than restoring additional customer load of the supplying Load Serving Entity / Transmission Owner. Any Load Serving Entity / Transmission Owner that is not operating in parallel with adjacent Load Serving Entities / Transmission Owners is free to restore or shed load in any manner or at any rate it may deem reasonable.

Local Control Centers that share common transmission or generation facilities (345 kV or below) must develop pre-arranged plans for the priority operation of these facilities during restoration. These plans include the maintenance of good communications during the period of the emergency.

The PJM dispatcher immediately establishes communications with the Transmission Owners and adjacent control areas experiencing the disturbance to establish the extent and severity of the separation. If direct communication channels are not functioning, communications are established via whatever means are available (i.e., routing calls through alternate channels, outside phone lines, radio communications, and / or PJM Satellite Phone System).

PJM Operator Responsibilities During the Restoration Process

The PJM System Operator has certain responsibilities regardless of the stage of the system restoration process. Transmission Owners will have primary responsibility of restoring their transmission system until such time as PJM is returning to normal operation and resumes authority over the transmission system. PJM actions during a system restoration include:

- PJM will coordinate all interchange schedules with external control areas.
- PJM will coordinate and direct all restoration of the 500 kV transmission system.
- PJM will develop and calculate area control error (ACE) as required when appropriate data is available to perform this calculation.
- PJM will coordinate and direct all transmission tie connections to external control areas.
- PJM will identify opportunities for interconnection between PJM internal Transmission Owners and / or neighboring control areas.
- PJM will collect system status information and provide status updates to members on system restoration status.
- PJM will conduct periodic System Operations Subcommittee (SOS) conference calls, as appropriate.
The following table presents the general steps that are performed to restore the PJM RTO following separation:

<table>
<thead>
<tr>
<th>Step</th>
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<tbody>
<tr>
<td>Ascertain System Status</td>
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<tr>
<td>Determine Restoration Process</td>
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<tr>
<td>Disseminate Information on System Status</td>
</tr>
<tr>
<td>Implement Restoration Procedures</td>
</tr>
<tr>
<td>Member Interconnection</td>
</tr>
<tr>
<td>PJM Assumes Frequency Control</td>
</tr>
</tbody>
</table>

**Ascertain System Status**

After a system disturbance occurs that results in a significant loss of customer load in a widespread area, it is important to determine transmission and generation loss, equipment damage, and the extent of the service interruption.

**Determine Restoration Process**

The purpose of this step is to develop and implement a restoration strategy. This step is performed after the status of the PJM RTO is determined.

**Disseminate Information**

The purpose of this step is to provide updated information of the system status to appropriate personnel. After system restoration plans are established and implemented, all participants must be apprised of system conditions.

**Implement Restoration Procedure**

The purpose of this step is to direct the restart of Generation Owners internal generation and load on-line generation in planned steps while maintaining system load, scheduled frequency, voltage control and reserves. This step is performed when a Transmission
Owner / Generation Owner is in a completely isolated or blacked-out condition and must restart their system without outside assistance.

**Member Interconnection**

The purpose of this step is to provide guidelines for the Transmission Owners to interconnect and control frequency, tie line, voltage schedules, share reserves and coordinate emergency procedures. This step is performed after the Transmission Owners have restarted and desire to interconnect and share reserves or Transmission Owners have coordinated plans to restart while interconnected.

**PJM Assumes Frequency Control**

This occurs when the control of an interconnected area is too burdensome for any one Local Control Center.
This Document has been mapped (in its entirety) to Section 3.0 of Appendix B of Directory #5 - Operating Reserve.

Approved by the NPCC Task Force on Coordination of Operation on November 5, 2002 as Reference Document RD-05.
Re-designated as Procedure Document C-38 on August 18, 2005.

Reviewed: August 18, 2005
1.0 Introduction

The NPCC Areas except Hydro-Quebec have agreed to share resources to meet operating reserve requirements. This procedure enables Areas to assist each other in meeting their ten minute reserve requirement.

2.0 Operating Procedure

2.1 Areas must commit sufficient resources to meet the reserve requirements prescribed by Northeast Power Coordinating Council (NPCC) Document A-6, Operating Reserve Criteria.

2.2 Each Area may count a contribution of 50 MW as ten minute non-synchronized reserve towards its ten-minute reserve requirement from participating Area(s), provided that the Regional Reserve Sharing Energy (RRSE) is available in the participating Area(s) and deliverable to the Area, and not activated.

2.3 A participating Area delivering RRSE to a contingent Area includes that energy as part of its ten minute reserve for meeting its ten minute reserve requirement.

2.4 NYISO serves as the coordinator of Regional Reserve Sharing (RRS). NYISO will continually monitor the availability and deliverability of RRSE among NPCC Areas. NYISO will communicate significant changes in the status of the availability and deliverability of RRSE to each NPCC Area and PJM.

2.5 Areas will inform the NYISO of the availability and deliverability of the RRSE described in this procedure during ordinary real time operational and operational planning communications. Exceptions and restrictions will be noted by all Areas.

2.6 Temporary restrictions in the availability of RRSE to be shared with other Areas by one Area do not preclude that Area from receiving RRSE from other Areas. Temporary restrictions in deliverability of RRSE by one Area to another Area do not preclude that Area from receiving RRSE from other Areas.

2.7 RRSE meets the sustainability requirements of NPCC Document A-6, Operating Reserve Criteria.

2.8 RRSE is physically delivered only if the contingent Area continues to need assistance, already being provided as Shared Activation Reserve Energy, beyond the thirty minute limitation for Shared Activation Reserve Energy. The NYISO will convert 100 MW of Shared Activation Reserve Energy to RRSE thirty minutes after the contingency. NYISO will inform the contingent and assisting Areas of the new adjusted shares related to the conversion from Shared Activation Reserve Energy to RRSE, with the greatest practical lead time. Refer to Attachment 1 for an illustration indicating the differences between Shared
Activation of Reserve and Shared Activation of Reserve with Regional Reserve Sharing.

2.9 RRSE is terminated when it is no longer needed by the contingent Area, but within sixty minutes of activation.

2.10 When a contingent Area terminates the delivery of RRSE from participating Areas, all Areas will employ a ten minute ramp in their interchange schedules.

2.11 If the RRSE from an assisting Area can no longer be delivered to the contingent Area, the assisting Area notifies the NYISO. Its RRSE being withdrawn will be reallocated to other assisting Areas to the greatest extent possible by the NYISO.

2.12 An Area may declare itself unavailable as a provider of RRSE if it becomes deficient in its synchronized portion of its ten minute reserve, or if it becomes deficient in ten minute reserve after including the effect of RRSE that it can receive from other Areas.

2.13 RRSE is available to an Area as a discrete 100 MW block; an Area may not request partial activation.

2.14 Although PJM is a participant in shared activation of reserve, it neither receives nor provides RRSE.

2.15 RRSE exchanged under this procedure will create inadvertent and will be treated in accordance with NPCC Document C-12, Procedures for the Shared Activation Of Ten Minute Reserve.
**References**

- *Operating Reserve Criteria* (NPCC Document A-06)
- *NPCC Glossary of Terms* (NPCC Document A-07)
- *Procedures for Shared Activation of Ten Minute Reserve* (NPCC Document C-12)

*References not mapped since all relevant materials are now incorporated into Directory #5.*
The above two charts demonstrate how Shared Activation Reserve Energy (SAR) is converted to reserve sharing energy 30 minutes after a supply-side resource contingency.

The upper chart shows idealized response when a SAR event occurs for the loss of 500 MW of generation. The contingent Area needs to provide 250 MW of additional generation within 15 minutes or less to do its share to assure a timely recovery. The assisting Areas also need to provide 250 MW of additional generation within 15 minutes to do their share to assure a timely recovery. In most realistic scenarios, the increased generation of the contingent Area might not begin for a minute after the contingency. The step schedule changes to effect the SAR may actually take place about 3 minutes after the contingency occurs. The provision of additional generation from the assisting Areas may not begin until about 4 minutes after the contingency occurs due to delays in communications. However, SAR events most often result in full recovery within 15 minutes of the contingency.

With an SAR event, the contingent Area most often cancels SAR assistance shortly after recovery if adequate resources are available to replace the assistance at that time. When adequate resources are not immediately available, the contingent Area may retain the assistance up to 30 minutes after the contingency. All 250 MW of assistance are ramped out over ten minutes by the contingent and assisting Areas.

The lower chart shows idealized response when a contingent Area activates RRSE. The first 30 minutes exactly matches that of an SAR only event that reaches the 30 minute delivery limit. However, at 30 minutes, only 150 MW of assistance is ramped out over ten minutes, while the remaining 100 MW of assistance already delivered in converted immediately.
into delivered RRSE. While the RRSE would typically be ramped out over ten minutes when it is no longer needed, it must be ramped out at no later than 90 minutes after the contingency.
Procedures for Inter-AREA
Voltage Control

Approved by the Task Force on Coordination of Operation on April 26, 2007
1.0 Introduction

This Procedure provides general principles and guidance for effective inter-
Area voltage control, consistent with the NPCC, Inc. Document A-02, “Basic
Criteria for Design and Operation of Interconnected Power Systems,” and
applicable NERC Standards. Specific methods to implement this Procedure
may vary among Areas, depending on local requirements. Coordinated inter-
Area voltage control is necessary to regulate voltages to protect equipment from
damage and prevent voltage collapse. Coordinated voltage regulation reduces
electrical losses on the network and lessens equipment degradation. Local
control actions are generally most effective for voltage regulation. Occasions
arise when adjacent Areas can assist each other to compensate for deficiencies
or excesses of reactive power and improve voltage profiles and system security.

2.0 Principles

Each Area develops, and operates in accordance with, its own voltage control
procedures and criteria which are consistent with NPCC, Inc. Criteria and
NERC Standards. Adjacent Areas should be familiar with the respective
criteria and procedures of their neighboring Areas. Areas should mutually
agree upon procedures for inter-Area voltage control. Whether inter-Area
voltage control is carried out through specific or general procedures, the
following should be considered and applied:

2.1 To effectively coordinate voltage control, location and placement
of metering for reactive power resources and voltage controller
status should be consistent between adjacent Areas;

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

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

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

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

2.6 reactive reserve of on-line generators;

2.7 shunt reactive device availability and switching strategy; and

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

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

3.1 Normal Voltage Conditions

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

- actual voltages are within applicable normal (pre-contingency) voltage ranges; and
- expected post-contingency voltages are within applicable post-contingency minimum and maximum levels following the most severe contingency specified in Section 6.1 of Document A-02, “Basic Criteria for Design and Operation of Interconnected Power Systems.”

Each Area should maintain a mix of static and dynamic resources, including reactive reserves.

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

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

This voltage profile, adjusted for changes in operating conditions, should be considered as the basis for determining which Area should implement necessary measures to alleviate abnormal voltage conditions affecting more than one Area as discussed in 3.2.10 below.
3.1.2 Each Area should anticipate voltage trends and initiate corrective action in advance of critical periods of heavy and light loads.

3.2 Abnormal Voltage Conditions

The bulk power system is operating with Abnormal Voltage Conditions when:

- actual voltages are outside applicable normal (pre-contingency) voltage ranges; or
- expected post-contingency voltages violate applicable post-contingency minimum and maximum levels following applicable NPCC, Inc. Normal or Emergency Criteria Contingencies.

3.2.1 If the bulk power system voltage is rapidly decaying, the Area, if identifiable, causing the decay should immediately implement all possible action, including the shedding of firm load, to correct the problem. All other Areas experiencing the rapid voltage decay should immediately implement all possible action, including the shedding of firm load, to correct the problem.

3.2.2 When an Area anticipates or is experiencing an abnormal, but stable, or gradually changing bulk power system voltage condition, it should implement steps to correct the situation. Recognizing that voltage problems are most effectively corrected by control actions as close to the source as possible, the Area should use its own resources, but may request assistance from adjacent Areas. Sections 3.2.3 to 3.2.8 provide a guide for the implementation of potential control actions with the provision that individual steps may be eliminated if considered ineffective for the particular situation.

3.2.3 The Area anticipating or experiencing the abnormal bulk power system voltage condition should implement the following control actions, with no implied priority, where effective and as available, in accordance with the Area’s respective voltage control procedures:

- depart from normal schedules of reactive power flows;
- adjust transformer taps;
- switch capacitors/reactors;
- adjust static VAR compensators;
- utilize full reactive capability of on-line generators;
- deploy synchronous condensers; or
- other actions as local voltage control procedures allow.
3.2.4 If the steps in Section 3.2.3 are insufficient to correct the problem, the Area anticipating or experiencing the abnormal bulk power system voltage condition should advise adjacent Areas of the condition and request a departure from normal reactive profiles, and request other assistance, if this will be effective. The adjacent Areas should assist by using some or all of the control actions listed in Section 3.2.3 where effective and as available, in accordance with the adjacent Area’s voltage control procedures.

3.2.5 If the steps in Sections 3.2.3 and 3.2.4 are insufficient to correct the problem, the Area experiencing the abnormal voltage condition should take the following actions, with no implied priority, where effective and as available, in accordance with the Area’s respective voltage control procedures:

- if effective, recall transmission outages;
- modify transactions with other Areas, and/or deviate from economic dispatch;
- operate generating units as synchronous condensers, where possible;
- reduce generator real power output to increase reactive capability;
- start additional generation;
- switch out internal transmission lines provided operating security limits are not violated;
- utilize dispatchable loads;
- activate available Demand Side Management (DSM) programs

3.2.6 If the steps listed in Section 3.2.5 fail to correct the problem, the Area experiencing the bulk power system voltage problem should request adjacent Areas to assist by using some or all of the steps listed in Section 3.2.5 where effective and as available.

3.2.7 If the steps listed in Section 3.2.5 and 3.2.6 are insufficient to correct the problem, the Area experiencing the problem should reduce customer supply voltage if this will improve transmission voltage levels. If, after this step, additional assistance is required, adjacent Areas should be requested to reduce customer supply voltage if this will be effective, providing the Area in difficulty has already taken this step.

3.2.8 If the problem is low voltage and it persists after the steps of Section 3.2.7 are exhausted, or if the bulk power system voltage
If the Area in difficulty is rapidly decaying, the Area in difficulty will shed firm load as required.

### 3.2.9 When assistance is provided by adjacent Areas, Emergency Transfer Criteria should not be exceeded.

### 3.2.10 If two or more Areas are experiencing voltage problems simultaneously, they will assist each other as above to the extent feasible. If the problem is so severe as to require the shedding of firm load, the shedding should be done to the extent required to control the situation.

**Note:** Terms in bold typeface are defined in the NPCC, Inc. Document A-07, “NPCC Glossary of Terms.”

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**Prepared by:** Task Force on Coordination of Operation

**Review frequency:** 3 years

**References:**

- *NPCC Glossary of Terms* (NPCC Document A-07)
- *Basic Criteria for Design and Operation of Interconnected Power Systems* (NPCC Document A-02)