



# Operating Procedures

ISO New England Operating Procedure No. 6

*System Restoration – Appendix A – System  
Restoration Guidelines*

Effective Date: October 12, 2007  
Revision No. 9

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## APPENDIX A - SYSTEM RESTORATION GUIDELINES

The following lists guidelines regarding the technical aspects of system restoration. 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. A more specific set of guidelines for restoration of the 345 kV system in the event of a complete blackout is presented in the flow chart in Appendix B. This flow chart and the various Local Control Center restoration procedures reflect the general guidelines. Where appropriate, the Local Control Center and the ISO procedures have been coordinated.

### A. Potential Actions to Stabilize Remaining Electrical Island(s)

After a blackout event, electrical island(s) could be formed due to the separation and survival of area(s) from the Interconnection. It is imperative to immediately monitor and assess conditions within these islands and take any warranted actions to stabilize their operations. Actions taken at Local Control Centers or Local Dispatch Centers to secure voltage, thermal or frequency conditions may include the switching of reactive devices, generation dispatch actions, transmission switching or load shedding.

At the ISO, operators may have to suspend use of automatic Desired Dispatch Points and change to manual dispatch orders. Also, depending on the status of inter-Area tie lines, ISO operators should appropriately select flat frequency or tie line bias control to stabilize frequency.

In the August 2003 islanding situation with underfrequency, ISO experienced frequency oscillations when flat frequency was selected. Modifications have now been made to go from the normal bias setting (approximately 1% of forecasted peak load) to a reduced value that approximates the expected actual frequency response when flat frequency is selected. This reduced bias setting should minimize system frequency oscillations by preventing excessive AGC change signals to Generators during islanding. To view the frequency bias values in use ISO System Operators can click on RTGEN, click Telemetry and then click the frequency bias button. The System Operations Principal Engineer or designee shall maintain both values and update annually.

If the New England power system is electrically isolated, the flat frequency control mode should be implemented. If still synchronously tied to one or more Control Areas / Balancing Authorities, combinations of different control modes may have to be explored. If all the areas are isolated from the Eastern Interconnection, use of flat frequency control by the largest area and tie line bias control by the other smaller area(s) could produce the best frequency regulation. If one of the areas is tied to the Eastern Interconnection, use of tie line bias by all areas should produce the best frequency regulation.

### B. Avoiding Unsynchronized Re-connects Between Electrical Islands

Circuit breakers of transmission circuits that opened during the blackout 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 reclosing of two disconnected systems whose frequencies and voltages happen to match for a sufficient period of time, by synchronism-check relays, may be followed by the trip of the circuit as the islands continue to pull away from each other and the circuit is too weak to hold them together. Also, there's a risk that circuits between electrical islands may be inadvertently closed during switching for system restoration. To avoid unsynchronized re-connects between electrical islands, switching procedures should a) contain steps such as inhibiting reclosing via SCADA commands or the opening of disconnects on circuits that comprise a split between electrical islands and; b) call for the use of paging systems or other means of notification to field personnel to alert them to events involving electrical islanding and increase awareness to the possible need for synchronizations before manual closures of breakers.

### **C. Restoration of Off-Site AC Power to Nuclear Generators**

The most critical power requirement after a blackout is the assurance of reliable shutdowns of nuclear Generators. The NRC requires these Generators to have reliable on-site power sources for shutdown operations. The expeditious restoration of alternative off-site AC power sources to nuclear Generators is imperative to promote the continued reliability of shutdown operations. Beyond this, the station service demands to return some nuclear Generators on-line cannot be met until off-site AC power is provided.

Nuclear Generators shall be notified when a stable power system is established following a system restoration. This notification enables the Nuclear Generator to come off of emergency on-site power sources and back onto the New England transmission system which ensures continued reliability of shutdown operations.

Between the Local Control Center and the ISO restoration procedures, at least two options for restoring off-site AC power to nuclear Generators have been provided.

### **D. Opening Circuit Breakers and Switches**

Local Control Center and company restoration procedures contain detailed instructions regarding the opening of circuit breakers and switches. In most cases, in-place substation procedures provide specific switching instructions to be followed in the event of a substation blackout. Some substations have equipment, which automatically switches into a desired post-blackout configuration.

In general, capacitors and customer loads will be opened and disconnected from the 345/230/115 kV transmission system. Similarly, circuit breakers or switches on the 345/230/115 kV transmission system will be opened. On the 345 and 230 kV, step-down transformers will be opened on the high side to avoid the simultaneous energization of a 345 or 230 kV circuit along with a step-down transformer. Step-down transformers off the 115 kV system will be opened on either the high or low side.

Operators should have station and distribution capacitors opened in locations where customer load can effectively absorb charging from transmission lines. This will help prevent high voltage conditions on the transmission system and excessive under excitation on Generators.

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Along these lines, operators should anticipate the use of any available reactors to help absorb charging and prevent high voltage.

### **E. Reviewing Load Tap Changer (LTC) Positions**

During system collapse, LTCs on autotransformers could move toward/to extreme tap positions. For example, if a gradual voltage collapse occurs (over several minutes), LTCs could move to full boost positions in an attempt to maintain subtransmission or distribution voltage. Upon collapse, the LTCs would remain in these positions and subsequent re-energization of the autotransformers could result in excessively high voltages on the low side systems that could result in equipment or load damage. Consequently, LTC positions should be checked prior to energization of autotransformers. If LTC positions are substantially off nominal, taps should be moved to nominal positions before energizing autotransformers.

### **F. Generator Start Ups and MW Loadings**

During system restoration, Generator MW loadings will be primarily dictated by minimum MW loading requirements to ensure Generator stability and the need to provide station service power to Generators without black start capability. Operators at generating stations should, in concert with Local Control Center operators, endeavor to start as many Generators as possible. More Generators mean stronger sources in terms of synchronized inertia and control of frequency and voltage.

Stronger sources will also afford more circuit energizations, Generator start-ups, spinning reserve, and load pickups (including larger block sizes of load pickups).

Once initial Generators have been brought on line and synchronized, they should pick up some/all the minimum load requirements for other Generators just prior to their startup/synchronization. Once these Generators start and synchronize, their minimum load requirements should be transferred to them by adjusting Generator loadings in the synchronized subsystem. This method of providing minimum load requirements to Generators is generally preferable to doing load pickups after a Generator has been synchronized.

### **G. Spinning Reserves**

Initially, when few Generators are on-line, operators will not have many options regarding spinning reserves. As restoration progresses and more Generators are phased in, operators should establish and maintain enough spinning reserve to cover loss of the Generator generating the most MW. Eventually, spinning MW reserves should be adequate to cover loss of the largest generating Generator and have additional reserve for continuing Generator start-up demands.

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## H. Load Pickups

### 1. Load Block Sizes

In general, pick up loads in block sizes that do not exceed 5% of total synchronized generating capability. One exception to this would involve initial phases of restoration where a large Generator with slow governor response is synchronized to a small Generator with fast governor response. To avoid overloading the smaller Generator after load pickup, block sizes should be restricted to 5% of the smaller Generator's MVA capability until (an) additional Generator(s) is/are synchronized.

### 2. Frequency Increase Prior to Load Pick up, Automatic Underfrequency Load Shedding

Large frequency excursions are to be expected during system restoration. To allay these excursions and prevent compounding them by the triggering of Automatic Underfrequency Load Shedding (AULS) and other subsequent cascading problems, operators should employ the following methods.

During initial stages of system restoration (electrical island sizes are roughly 500 MW or less) the block sizes of load pickups are most likely to be at/near the general limit of 5% of synchronized generation capability and large frequency excursions are most probable. Operators can compensate for the frequency dips by first increasing frequency to as high as 60.3 hertz prior to load pickup. Operators may achieve another layer of reliability by initially avoiding, if possible, the restoration of feeders with AULS. (Initially avoiding AULS is preferred but may not be possible based on substation design). If AULS feeders must be picked up, operators should initially opt, if possible, to restore those set at 58.8 hertz.

As island sizes grow to several hundred MW and the ratio of load block sizes to synchronized generation decreases, smaller increases in frequency prior to load pickup will become appropriate. Also, load pickups should now restore the 15% portion of load with AULS at 58.8 hertz.

Finally, as island/system sizes reach a thousand(s) of MW, load block sizes should become a small percent of synchronized generation and increasing/maintaining frequency after rather than prior to load pickups should be sufficient. Full AULS capability (10% at 59.3 hertz and 15% at 58.8 hertz) should be restored and maintained. This will provide backup protection for generation contingencies in these larger size islands/systems.

During restoration, operators should observe analog/instantaneous recordings of frequency response to actual load pickups (if available) and tailor their frequency increases and load block sizes to prevent excessive frequency excursions.

### 3. Cold Load Pickup

During system restoration, operators will be restoring feeder loads that have been deenergized for unusually long periods of time (commonly referred to as "cold load"). The longer the deenergization period, the greater the loss of typical on/off cycling and other types of diversity in the load. Upon reenergization of the load, simultaneous full demands of all the various load components can be encountered. Consequently, operators should anticipate cold load pickups that are 1.5 - 5 times greater than normal feeder loads. Also, the longer the deenergization period, the longer it will take for the cold load magnitude to decay to a more typical value. After performing several load pickups, operators should get a better feel of cold versus typical feeder loads.

## I. Salient Electrical Concerns During System Restoration

Reliable frequency and voltage performance (both transient and steady state) and reliable circuit energizations are major concerns during system restoration, especially during initial stages. The following general guidelines address these concerns.

### 1. Transmission Line Charging

Anticipate the introduction of shunt MVAR charging from line energizations and ensure that adequate reactive control exists prior to line energizations. The following are typical charging values: .88 MVAR/mile for 345 kV, .28 MVAR/mile for 230 kV, and .07 MVAR/mile for 115 kV. These figures show charging to be a critical concern on the 345 kV, a significant factor on the 230 kV but much less of a concern on the 115 kV. Charging on cables is much higher than that of overhead lines. Typical charging values for cables are: 20 MVAR/mile for 345 kV and 4 MVAR/mile for 115 kV. These values, combined with a greater likelihood of switching surge difficulties, underscore the need to delay the energization of cables until later stages of system restoration. A list of 345 kV circuits and their charging levels are provided in Appendix C. A list of shunt devices and reactors within New England are provided in OP-12 Appendix B.

### 2. Voltage Schedules at Generators

Generating stations should work to maintain voltage schedules below normal levels during system restoration. This will help combat shunt MVAR charging from lightly loaded transmission lines and consequential high voltage and excessive switching surges. Lower voltage schedules will reduce transmission line MVAR charging (which is a function of voltage squared) and promote leading operation of Generators and thus the absorption of transmission line MVAR charging. As island/system sizes increase and significant real power MW flows start to occur on transmission circuits, normal voltage schedules at generating stations may become preferable. In any case, decisions on voltage schedules should be based on actual system voltage levels and Generator reactive loadings versus their leading reactive power limits. If a Generator is at/near its leading reactive power limit, other options for absorbing reactive power or reducing the amount of reactive power that has to be absorbed should be exercised to restore leading reactive reserve on Generators.

### 3. Circuit Energizations

Perform circuit energizations in a deliberate manner, checking the status of all associated facilities before and after energization. Synchronism, reactive conditions, and switching surges should be considered. In general, excessive switching surges are not anticipated for energizations on the 115 or 230 kV.

In the early stages of system restoration, 345 kV line or 345/115 kV transformer energizations should be done with a source that is electrically close to the energization, and has a total capability of 150 MVA or more (could be one or more synchronized Generators). Even then, only one to three 345 kV facilities could be energized reliably depending on line length or transformer characteristics. As restoration progresses and the total capability of synchronized sources builds up to several hundred MVA spread out over the 345 kV system, the possibility of excessive switching surges decreases substantially.

The simultaneous energization of a 345 kV transmission line and a 345 kV step-down transformer should be avoided. In cases where this is not possible (no breaker between the line and transformer), the energization of these circuits should be done with a strong nearby source or in later stages of system restoration when sources are strong.

In general, a reactor connected to the tertiaries of 345 kV step-down transformers should be closed-in prior to energization of the transformers. This will help prevent excessively high switching and steady state voltages. Prior to switching, operators should confirm that the reactor will be beneficial, and be able to be supported after switching. In cases where multiple reactors are available, operators should decide how many reactors can/should be energized along with the 345 kV transformer.

If upon energization, a circuit immediately trips out due to relay protection, operators should try to have the lightning arrestors at the terminals of the circuit visually inspected for damage before making another attempt to energize the circuit. If inspection is not possible/timely, parties should be aware of and accept an increased risk for equipment damage during subsequent attempts to energize the circuit and other nearby circuits. The transmission equipment of most concern would be autotransformers.

### 4. Synchronizations

Generating stations are the preferred locations for synchronizing Generators, islands or systems together. These stations have synchronizing equipment which is needed for regular Generator phasing. Also, station operators should be versed in synchronizing techniques. In the restoration procedures, some synchronizations are planned at transmission (vs. generating) stations. For these cases, the necessary synchronizing equipment, operator knowledge and communication links to predefined generating stations (to match frequency) have been considered.

At the circuit breaker where electrical islands will be synchronized, the voltage magnitude of the two systems must be matched as close as possible. A rule of thumb would be to close the circuit breaker with not more than 3% voltage difference

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between the two islands. The island with the dynamic voltage control device closest to the synchronizing location should change the voltage. The frequency of the two systems must also be close. The difference should be no greater than  $20^\circ$  of relative phase angle rotation per second, or a synchroscope rotation of no more than one (1) full revolution in 18 seconds. The smaller island should control the frequency and be running at the slightly higher frequency. Finally, the sync-scope phase should be as close to the 12 o'clock position as possible and certainly within  $\pm 3$  minutes (or about  $\pm 20^\circ$ ) of vertical upon breaker closure.

#### **J. Inter-Local Control Center Ties**

The synchronization/energization of inter-Local Control Center ties should occur during fairly early stages of system restoration. This would minimize problems associated with having to synchronize many small islands or trying to match frequencies of two large islands. It would also promote the most effective use of available resources to restore the system in the least amount of time. Appendix D lists the Inter-Local Control Center Ties operating at 115 kV and above.

#### **K. Inter-Area Ties**

The same reasons for early establishment of inter-Local Control Center ties apply to inter-Area ties. However, the lack of direct control over switching operations in other pools and their overall status/reliability should be considered before establishing ties. NPCC Document C35 – Inter-Area Power System Restoration Procedure provides more detailed information on how Control Area / Balancing Authority System Operators should establish and maintain Inter-Area tie lines. ISO operations personnel should reference NPCC C35 during a system restoration event.

Reliable operation of most HVDC converters requires that strong AC systems exist. For this reason, operators should not attempt to energize HVDC ties during early phases of system restoration unless it is known that their design will allow reliable operation with weak AC systems. Appendix E lists the Inter-Area Ties and guidelines for when the HVDC ties can be reliably restored.

**OP 6 APPENDIX A REVISION HISTORY**

**Document History** (This Document History documents action taken on the equivalent NEPOOL Procedure prior to the RTO Operations Date as well revisions made to the ISO New England Procedure subsequent to the RTO Operations Date.)

<b>Rev. No.</b>	<b>Date</b>	<b>Reason</b>
Rev 1	07/22/98	
Rev 2	09/01/2002	
Rev 3	06/11/2004	
Rev 4	11/09/2004	
Rev 5	02/01/05	Updated to conform to RTO terminology
Rev 6	08/23/06	Updated to enhance technicalities for Restorations
Rev 7	10/13/06	Revised to clarify material in old Appendices D and E are now referenced in OP 12 Appendix B
Rev 8	09/17/07	Added communication to nuclear Generators when grid is available for station service
Rev 9	10/12/07	Revised to clarify changes with frequency bias settings when 'Flat Tie Line' is selected.