# Operating Reserves White Paper

ISO New England Inc.
February 1, 2006

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# Section 1
# Overview

The mission of ISO New England Inc. (the ISO) is to plan and operate the grid in a reliable manner and administer fair and efficient markets. A significant part of running a reliable grid is ensuring that adequate real-time operating-reserve capacity is available to respond to system contingencies. A contingency is a failure of an element of the power system. Typical contingencies considered in determining power system reliability are as follows:

- Loss of a supply source, such as a generator or, in the case of New England, the loss of a direct current interconnection to another control area

- Loss of a transmission element, such as a 345 kV transmission line

- In certain circumstance, loss of multiple elements, such as two lines, a line and a generator, or all generators in a station that are vulnerable to common-mode failing, which may be considered as a single contingency

This paper examines the methodology for the determination of the magnitude of real-time operating reserves and the process by which they are dispatched. The paper is organized as follows:

- Section 2 provides a broad introduction to the types of operating reserves required in the New England Control Area and a high-level overview of the ISO's unit-commitment process.
- Section 3 details the reliability requirements imposed on the ISO by different governing and regulatory bodies and describes how the different types of operating reserves are used to meet these requirements.
- Section 4 explains ISO's methods to determine the commitments necessary to satisfy the reliability requirements.
- Section 5 explains the processes and tools employed by the ISO to implement these requirements.
- Section 6 contains two case studies that demonstrate how the reliability requirements result in the unit commitment in import-constrained areas.

# Section 2
# Introduction

Operating reserves can be viewed as the bulk power system's real-time dispatch insurance policy. They provide for additional supply above what is otherwise needed simply to meet forecasted real-time system energy demand. Operating reserves allow the ISO's dispatch processes to respond to significant and unexpected imbalances between supply and demand without interrupting load.

The clearing software for the Day-Ahead Energy Market schedules sufficient resources to meet the cleared demand while observing all identified constraints, including the forecasted regional reserve requirements. After the day-ahead market closes, and the re-offer period has ended, the ISO conducts a Reserve Adequacy Assessment (RAA) based on the ISO's forecast demand for the following operating day. The objective of the RAA is to ensure that all identified constraints, including the operating-reserve requirements, not satisfied by schedules for physical resources in the day-ahead market or by self-schedules during the re-offer period are met. The RAA process may result in additional resources being scheduled.

Generators that are not dispatched in merit for their full minimum run time, as determined by the applicable nodal locational marginal price (LMP) in relation to their offer data, or generators that are being dispatched above their self-scheduled amounts may be eligible for additional compensation through operating reserves. This operating-reserve compensation ensures that generators providing energy or reserves that experience overall revenue shortfalls or, in some cases, lost opportunity costs are made whole for any expenses not recovered through the sum of daily energy market payments. These payments are called Net Commitment-Period Compensation (NCPC) or Transmission Tariff payments, depending on the service the generator has provided. Both the Day-Ahead Energy Market and Real-Time Energy Market calculate four types of operating-reserve compensation, as follows:

- <u>First-contingency NCPC</u> is paid to eligible generators that are providing energy or operating reserves and that are not flagged for another type of ORC.
- <u>Second-contingency NCPC</u> is paid to generators that are required for local second-contingency reliability within a particular reliability region on a particular day.
- <u>Voltage Transmission Tariff payments</u> are paid to generators providing voltage control to the transmission system.
- <u>Distribution Transmission Tariff payments</u> are paid to units that manage constraints on the low-voltage system for local network reliability.

The ISO pays operating-reserve compensation to: 1) eligible pool-scheduled generators; 2) self-scheduled generators for the megawatts (MW) above self-scheduled levels if dispatched in real-time; and 3) market participants with external dispatchable transactions that have a shortfall between their revenue (calculated using clearing prices in the energy market) and their offer data (calculated using their energy offer, start-up fee, and no-load fee). Eligible generating resources may receive operating-reserve compensation on a daily basis if the ISO commits them in merit (or out of merit for a portion of their minimum run time) for energy (first contingency) or out of merit for voltage control and voltage support, for local network reliability (distribution), or to provide reliability for second contingency.

First- and second-contingency NCPC is allocated to market participants, while voltage and distribution transmission tariff payments are allocated to transmission customers and local distribution companies through the provisions of the New England Open Access Transmission Tariff (OATT). Table 1 illustrates the relationship between operating requirements and financial settlements.[1]

**Table 1 Relationship between Supplemental Physical Commitments and Financial Settlements**

| Physical Commitments | Financial Settlement | | | |
|---|---|---|---|---|
| | First Contingency NCPC | Second Contingency NCPC | Voltage Tariff Payments | Distribution Tariff Payments |
| Systemwide first contingency (stability, thermal) | X | | | |
| Systemwide and regional out-of-merit energy | X | | | |
| Regional second contingency (thermal) in import constrained areas [a] | | X | | |
| Reactive power for voltage control or voltage support | | | X | |
| Local transmission support | | | | X |

[a] The current import-constrained areas in New England are Boston/Northeast Massachusetts, Connecticut, Southwest Connecticut, and Norwalk/Stamford.

[1] For details of compensation arrangements, see the *2004 Annual Markets Report* at: <http://www.iso-ne.com/smd/market_analysis_and_reports/public_forum_and_annual_report/2005_Annual_Forum/>.

# Section 3
# Reliability Requirements

The existing requirements for power system reliability come from the North American Electric Reliability Council (NERC) and Northeast Power Coordinating Council (NPCC). In general, NERC and NPCC standards, criteria, and procedures prescribe reliability by mandating that the New England power system be planned and operated to protect and recover from specific types of contingencies. The potential consequences of a contingency dictate the manner in which the system must prevent the contingency or be protected from it. To ensure a reliable grid, some pre-contingency responses are required, and some post-contingency consequences warrant rapid responses. Transient instability or voltage collapse can occur immediately (within a few AC cycles). Each has severe consequences. For these instances, pre-contingency limits are developed and honored. In the case of thermal overloads, more time is available to respond before equipment damage occurs. Quick-start generating resources and other resources that are able to respond quickly are generally able to meet this response requirement.

NERC sets umbrella Reliability Performance Standards for all Reliability Coordinators, Balancing Authority Areas and Transmission Operators in North America.[2] The ISO fulfills these Standards working together with the Market Participants in New England. NPCC sets reliability criteria specifically applicable to the northeast region based on the NERC performance standards.[3] Finally, the NERC and NPCC criteria have been implemented through the ISO procedures to plan and operate the New England power system. The ISO procedures are applied to address both systemwide and subregional (area) reliability. Systemwide procedures address the New England Area. Subregions within the New England Area are defined by transmission interfaces, which can be categorized by the nature of their physical limitations. (This paper uses the terms subregion and area interchangeably.)

## 3.1 Systemwide Reliability

NERC requires that "each Balancing Authority (i.e., the New England Area operated by the ISO) shall have access to and/or operate Contingency Reserves to respond to Disturbances."[4] Such contingency reserves must be sufficient to comply with the Disturbance Control Standard and, at a minimum, each control area must carry enough contingency reserves to meet the most severe single contingency on its system. In New England the most severe single contingency (first contingency) is often the largest committed generator.

NPCC further details NERC requirements and states that a system requires sufficient operating capacity to meet forecast load, including an allowance for error, to protect against equipment failure that has a reasonably high probability of occurrence, and to provide adequate regulation of frequency and tie-line power flows.[5] NPCC Criteria A6 provides that control areas must meet these objectives by mandating a 10-minute reserve requirement at least equal to a first contingency loss multiplied by a contingency-

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[2] *See:*<http://www.nerc.com/>.

[3] *See:* <http://www.npcc.org/>.

[4] NERC Standard BAL-002-0 Disturbance Control Perfromance The document is available at: <http://www.nerc.com/~filez/standards/Reliability_Standards.html>.

[5] NPCC Criteria A6, *Operating Reserve Criteria*. The document is available at: <http://www.npcc.org/PublicFiles/Reliability/CriteriaGuidesProcedures/A-06.pdf>.

reserve adjustment factor.[6, 7, 8] The purpose of 10-minute operating reserve is to return the flows on inter-Area tie lines to pre-contingency values within 10 minutes after the first contingency occurs and to restore system frequency to its predisturbance condition. In addition to the 10-minute requirement, NPCC requires 30-minute reserves equal to one half of a control area's next largest contingency (second contingency.)[9,10] The 30-minute requirement provides reserves to help re-prepare to withstand the second contingency in 30 minutes after the first contingency occurred. During the shortages of 10-minute operating reserves 30-minute reserves can also be redispatched to maintain 10-minute reserve at the prescribed value. If the 10-minute and 30 minute reserve requirements cannot be met, emergency actions must be taken. If activated, operating reserves should be sustainable for at least 1 hour from the time of activation.

Additionally, NPCC standards dictate that 30-minute reserve levels must be restored fully within four hours after reserve use if the control area becomes deficient. Lastly, NPCC requires that an Area shall maintain reserve on automatic generation control resources to meet the NERC control performance standards.

Within New England, ISO Operating Procedure 8, *Operating Reserve and Automatic Generation Control* (OP 8), describes the New England-specific application of NERC and NPCC standards by requiring that: "Operable Capability, in addition to the quantity required to meet the actual New England Area load, is required to reliably operate the New England interconnected electric power system."[11] Such additional capability provides for:

- Loss of generating equipment within the New England Area or within any other NPCC Area
- Loss of transmission equipment within or between NPCC Areas that might result in a reduction of energy-transfer capability within New England or between the New England Control Area and any other control area
- Regulation in the New England Area
- Errors in forecasting New England Area loads

The ISO meets the requirements of OP 8 by dispatching to provide a 10-minute reserve equal to its largest first contingency loss. This 10-minute reserve must be maintained at all times. In case the 10-minute reserve becomes deficient, it must be restored immediately and carried on regardless of the price.[12] Of

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6 Ten-minute reserve is the sum of synchronized and nonsynchronized reserve that is fully available in 10 minutes from the time first requested.

7 First contingency is the loss of a facility connected to the system. In this document, an “initial” contingency is the “first” contingency. The “next” contingency the system is being protected from is referred to as the “second” contingency.

8 The contingency reserve adjustment factor can be greater than one if the area has poor performance during a disturbance event and is directly proportional to an area's failure during an event.

9 A second contingency is the subsequent loss of another element of the power system.

10 Thirty-minute reserve is the sum of synchronized reserve and nonsynchronized reserve capability that is fully available within thirty minutes from the time first requested, excluding the capability assigned to meet ten-minute reserve requirements.

11 ISO OP 8 is available at: <http://www.iso-ne.com/smd/operating_procedures/OP8_SMD_FIN.doc>.

12 ISO achieves this by dispatching additional generation or, if the additional generation is not available, by going into OP 4.

that total requirement for 10-minute reserve, the ISO maintains at least 50% as ten-minute synchronized reserve with the remainder being 10-minute nonsynchronized reserve.[13, 14, 15] In addition to maintaining the 10-minute reserve, the ISO maintains 30-minute reserve equal to one half its second largest contingency.[16] [17] Figure 1 illustrates the above mix of systemwide reserves.

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[13] Ten-minute synchronized reserve means the reserve capability of a: 1) generating unit that can be converted fully into energy within 10 minutes from the request of the ISO dispatcher, or 2) a dispatchable load pump that can reduce energy consumption to provide reserve capability within 10 minutes from the request of the ISO dispatcher. The generating units and dispatchable load pumps provide this capacity electrically synchronized to the ISO transmission.

[14] Ten-minute nonsynchronized reserve means the reserve capability of: 1) a generating unit that can be converted fully into energy within 10 minutes from the request of the ISO dispatcher, provided by units that are not electrically synchronized to the ISO transmission system, or 2) the reserve capability of a dispatchable load that can be fully utilized within 10 minutes from the request of the ISO dispatcher to reduce consumption.

[15] The base NPCC ten-minute reserve requirement is that 100% of the ten-minute reserve be synchronized reserve. However, based upon past performance during disturbance recoveries, the ISO has discretion to lower this value and has currently reduced it to 50%.

[16] The ability to securely withstand the next contingency in 30 minutes may have to rely on such actions as initiating OP 4 "Action During A Capacity Deficiency" in addition to having 50% of the second contingency in 30-minute reserve.

[17] The ISO also maintains replacement reserves (not shown in Figure 1) equal to 25% of its second largest contingency to ensure recovery of its ten-minute reserves. See OP 8 for more details: <http://www.iso-ne.com/smd/operating_procedures/OP8_SMD_FIN.doc>.

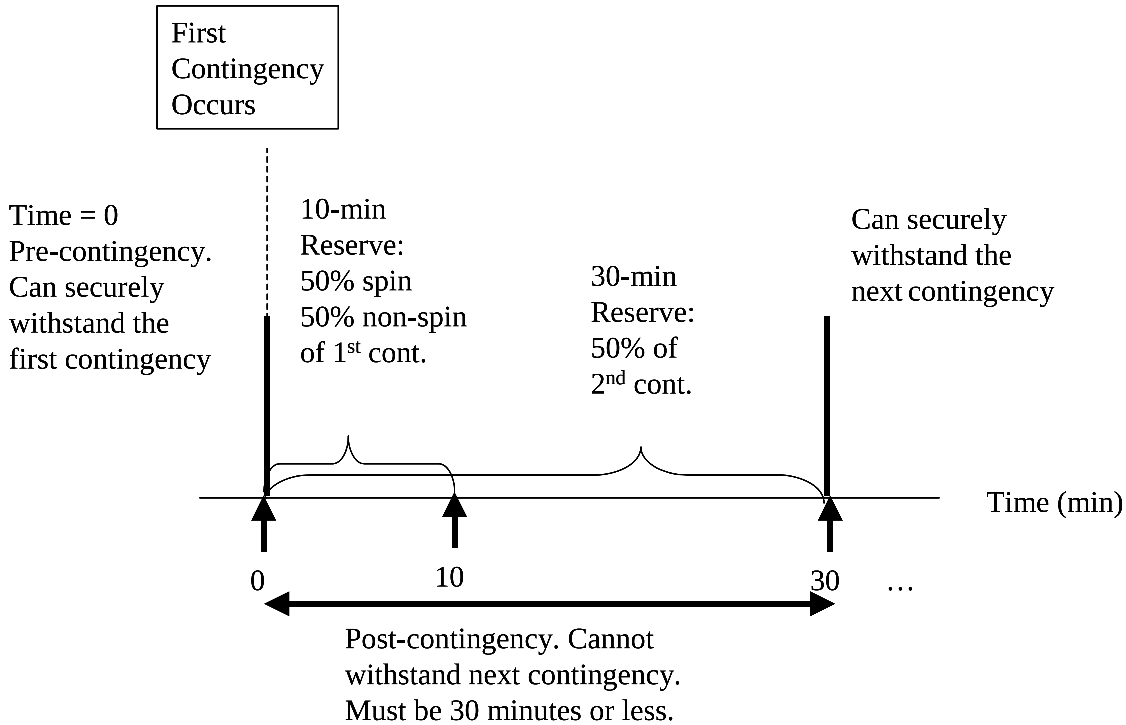


**Figure 1** Systemwide reliability requirements.

By maintaining these levels of operating reserve, the ISO meets the NERC control performance standards and NPCC standards for the New England power system.

## 3.2 Subregional Reliability

The ISO criteria for subregional reliability also have their basis in NERC and NPCC requirements. NERC requires that following a contingency or other event that results in a violation of a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL), the Area shall return its transmission system to within SOL and IROL limits or its precontingency state as soon as possible, but within thirty minutes.[18] The ISO also has to withstand another contingency within 30 minutes even if a SOL violation did not occur upon the first contingency. Figure 2 illustrates this requirement.

[18] IROL and SOL define the acceptable operating boundaries. Returning the transmission system to within operating security limits effectively means that dispatch actions have been taken that will allow the system to withstand its next worst contingency. For more details, see NERC Standards TOP-004, TOP-007, and TOP-008. The document is available at <http://www.nerc.com/~filez/standards/Reliability_Standards.html>.

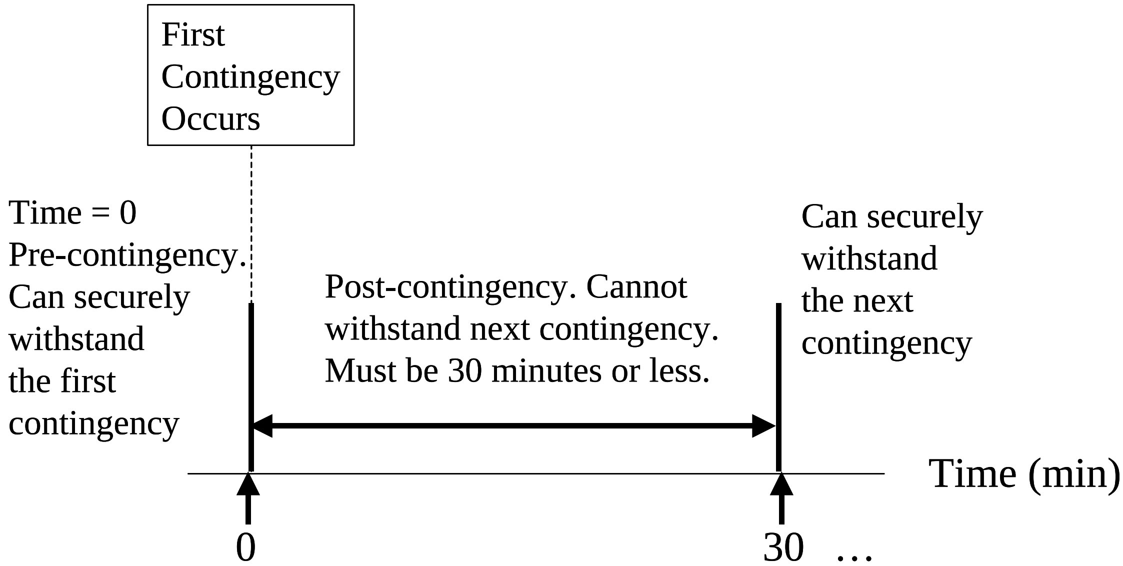


**Figure 2** Subregional reliability requirements.

NPCC Criteria A6 requires the distribution of operating reserve available to a control area to ensure that it can be used without exceeding individual power system element-transmission ratings or interface-transfer limits.

To implement these NERC and NPCC requirements ISO OP 8 mandates the ISO to maintain reserve levels within specific New England subregions that meet subregional reliability requirements. OP 8 requires operating reserve to be distributed to ensure that the ISO can fully use it for any probable contingency without exceeding transmission system limitations and to ensure operation in accordance with NERC, NPCC, and ISO operating policies and procedures.

In addition, ISO Operating Procedure No. 19, *Transmission Operations* (OP 19), requires that, if necessary, "Emergency Actions should be taken to maintain or restore power system conditions to at least those prescribed for operations under Emergency Conditions."[19] Pre-contingency, OP 19 requires that the power system be operated such that the loss of any power system element will not cause the post-contingency power flows to exceed the long-term emergency (LTE) rating of any other power system element.[20] In accordance with NPCC criteria OP 19 further stipulates that upon the loss of the first-contingency element, the ISO has thirty minutes to restore the loading on the transmission system to acceptable levels to handle the next contingency.

The next section demonstrates how these standards translate into the development of generation requirements for the pool and subregions.

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[19] ISO OP 19 is available at: <http://www.iso-ne.com/smd/operating_procedures/pre_smd/OP19FIN.rtf >.

[20] If the flow exceeds LTE, it should be returned to below LTE within 15 minutes. For details, see OP 19, Appendix B.

# Section 4
# Determination of Generation Requirements for First- and Second-Contingency Protection

To comply with NERC, NPCC, and ISO reliability criteria, the ISO continually monitors the bulk power system to ensure that sufficient resources are in place for the system to withstand a first contingency and to recover (within thirty minutes) from that first contingency to a state where it can withstand the occurrence of a next, or second, contingency without violating applicable reliability criteria or creating an unacceptable impact on other control areas. A crucial part of this process is the calculation of requirements for on-line generation needed to maintain both systemwide and subregional reliability, given the physical limitations of the transmission interfaces of the transmission system. Contingency protection can be achieved by limiting power transfers across an interface.

The following paragraphs describe transmission interfaces, specific calculations used to determine interface limits, and the calculation used to determine the generation requirements for operating the transmission within those limits. Specific examples are included to illustrate the computations for calculating the generation requirements that enable the power system to withstand first contingencies and recovery from those first contingencies in accordance with the criteria for bulk power system security.

## 4.1 Transmission Interfaces

A transmission interface is comprised of at least one, but in most cases, several monitored transmission elements that define the boundary of a cohesive area of the power system. The ISO performs routine off-line studies to determine interface limits and identify system conditions that would have a significant impact on those limits. The study results are used to determine and maximize interface transfer capabilities based on planned or actual system conditions. Power system interfaces can be described in terms of the physical nature of their limitations, which can take at least one of three forms—thermal, voltage/reactive, or transient-stability limits.

### 4.1.1 Thermal Limits

Thermal limits are determined for each interface and are based on the ability to transfer power into the sub-area without exceeding the current-carrying capability ratings of any transmission element upon a contingency. Transmission-element loadings typically are limited by the amount of heat generated at maximum loading. Exceeding these limits can result in equipment failure. OP 19 defines four levels of thermal limits for transmission elements—normal, long-term emergency, short-term emergency (STE), and drastic-action limit (DAL).[21] In each case, the limits are defined in terms of the maximum period during which the element may be operated at that load level. The impact of first contingencies on thermal constraints is evaluated in day-ahead and real-time by the power flow and contingency analysis software.[22]

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[21] See Appendix B in OP 19.

[22] This and other software are discussed later in this section.

### 4.1.2 System Voltage and Reactive Limits

Voltage/reactive transfer limits are determined for each transmission interface to prevent unacceptable voltage/reactive response to first contingencies. The limits reflect the maximum secure interface transfers above which widespread post-contingency voltage instability and collapse could result from first contingencies. Voltage instability and collapse can result in a wide spread loss of generation and/or load.

### 4.1.3 Transient-Stability Interface Limits

Limits are determined for each transmission interface that will ensure transient stability when first contingencies occur. Adherence to these limits avoids unacceptable consequences ranging from severe equipment damage to systemwide instability and possible system separation and islanding. The ISO conducts studies to identify the impact of transmission-element outages and develop situation-specific limits to address unusual system operating configurations.

### 4.1.4 Subregions

The difference between an import and export subregion (or area) is the direction of predominant net-power flow across a predefined transmission interface that defines the area. Both import and export areas have interface-transfer limits to protect against thermal, voltage/reactive, or transient stability limits. Also, both import and export areas must be able to sustain a first contingency and, within 30 minutes, be re-dispatched to withstand the next worst contingency. However, the reliability issues surrounding import and export areas differ. For export areas, generation within the area must be reduced when the first-contingency dispatch of area resources exceeds the area’s load plus export limit. For import areas, generation within the area must be increased and load within the area may have to be reduced when the total of the area’s import capability plus dispatched internal resources fall below the load within the area.

In New England, the most restrictive interface limits for export-constrained areas may be thermal, voltage/reactive, or transient stability based. The interface limits for import-constrained areas typically are thermal or voltage/reactive based.[23]

## 4.2 Interface Limits and Generation Capacity Requirements for First-Contingency Protection

Each day, the ISO identifies interface limits for the next operating day based on first contingencies. These limits are used as inputs to develop the day-ahead market schedules. These limits are periodically updated as part of the RAA process.

For export areas, the ISO determines the maximum allowable amounts of area generation based on the following relationship:

(1) *Maximum Export-Area Generation =*

*Area Load + First-Contingency Interface Export Limit*

[23] Based on the nature of transient-stability phenomena, only export areas have transient-stability interfaces and require such limits.

where *First-Contingency Interface Export Limit* is the most restrictive limit among thermal, voltage/reactive, and transient stability limits.

For the import areas, minimum amounts of required area generation (energy) are based on the following relationship:

(2) *Minimum Import-Area Generation Requirement* =

max {0, (*Area Load – First-Contingency Interface Import Limit*)}

where *First-Contingency Interface Import Limit* is the most restrictive limit of the thermal and voltage/reactive limits, and

for any two numbers a and b, max {a,b} = b if a ≤ b, and equal a otherwise. The following example illustrates the determination of the Minimum Import-Area Generation Requirement to provide first-contingency protection for an import-constrained subregion.

<u>Example 1: Planning Generation for First-Contingency Protection of an Import-Constrained Area</u>

Assume that a day-ahead New England load of 17,350 MW is forecast for hour ending 2:00 p.m. For the import-constrained area X, which is approximately 14.4% of New England's load, determine the area generation requirement for this hour assuming the most restrictive import limit into area X for first-contingency security is 2,000 MW.[24]

Solution:

Area X load = 14.4% of 17,350 MW = 2,500 MW

The area X load is greater than the X interface import limit, and the minimum generation requirement for this hour according to (1) is max {0, (2,500 MW – 2,000 MW)} = 500 MW. Therefore, the generation commitment within the X import area for this hour must be at least 500 MW to serve the area's load and provide first-contingency protection.

Many subregions of New England can naturally withstand a first contingency and provide for the next contingency coverage without having to take any additional actions. For all export areas, 30-minute recovery is inherently achievable since it involves reducing generation resources within the export area. In import-constrained areas of New England, however, where existing resources do not inherently provide for acceptable recovery from a first contingency within the 30-minute period allowed, the ISO must act to ensure that an adequate recovery is possible.

## 4.3 Area Recovery from a Contingency and Second-Contingency Protection

All areas of the system must be operated such that within 30 minutes following a contingency, the system can be re-dispatched to withstand the second contingency without jeopardizing the reliability of the bulk

[24] A first contingency import limit of 2,000 MW means that with actual imports of 2,000 MW or less, the system can withstand the single worst contingency that could impact area X without violating the applicable reliability criteria.

power system. At present, the following import-constrained areas in New England require a daily evaluation to ensure that second-contingency security with appropriate 30-minute recovery is in place at all times:

- Boston/Northeast Massachusetts (NEMA/Boston)
- Connecticut (CT)
- Southwest Connecticut (SWCT)
- Norwalk/Stamford (NWST)

These areas require a daily evaluation due to the limited 30-minute resources available to the operators and the impact on the bulk power system if the interface experiences a contingency when the interface is above its transfer capability. Additional resources may have to be committed to cover local second-contingency requirements when first-contingency resources and existing transmission limits are insufficient to provide this level of protection. The following two subsections detail measures for providing area recovery from a contingency and second-contingency coverage. These measures then are used in equations that calculate second-contingency limits and the requirements for generation capacity.

### 4.3.1 Interface Limits and Generation Capacity Requirements for Second Contingency

Each day, the ISO identifies interface limits for the next operating day based on second contingencies. These limits are used as inputs to develop the day-ahead financially binding market schedules. These limits are periodically updated as part of the RAA process.

Reliable operation of import-constrained areas requires a calculation of second-contingency interface limits. The modeling of the post-first contingency, or "N-1," transmission condition in a secure power flow case determines a second-contingency interface limit, based strictly on the capability of the remaining transmission system and operating generation in the area. Four types of first/second contingency pair scenarios can occur, as follows:

1. The loss of the two most critical transmission lines serving the area
2. The loss of the most critical transmission line followed by loss of the largest area generator
3. The loss of the largest area generator followed by loss of the most critical transmission line
4. The loss of the two largest area generators

Note that the post-second contingency state of a given area is the same for Scenarios 2 and 3, given the same set of pre-contingency conditions. Because they are essentially identical cases, when one is referenced, both are implied.

Given the actual mix of transmission system capabilities and generators in New England, Scenarios 1 and 2 typically result in the most constraining subregion limits. Scenario 1, the loss of the two most critical transmission lines serving the area, is often referred to as a "line–line" or "second-line" limit. Scenario 2, the loss of the most critical transmission line followed by loss of the largest area generator, is often referred to as a "line–generator" or "second-generator" limit.

The ISO action to be prepared for second contingency depends on the required response speed and the ability to activate alternate resources within that time. If the consequences of a second contingency require rapid response (e.g., voltage instability and collapse), resources must be configured to allow response prior to or in some cases simultaneously with the second contingency. If the consequences allow for longer response times (e.g., violation of thermal limits due to thermal overloads), then more options may be available and allow action after the second contingency. Transient stability limits do not occur as the most restrictive in the reliability areas. Table 2 summarizes the kinds of limits that may occur in four New England's import-constrained areas:

**Table 2 Applicable Most Restrictive Limits in Import-Constrained Areas**

| Most Restrictive Limit | Import-Constrained Area | | | |
|---|---|---|---|---|
| | Boston | CT | SWCT | NRST |
| **Thermal** | X | X | X | X |
| **Voltage** | | X | X | |
| **Stability** | | | | |

To ensure that unit commitment provides enough resources within an import-constrained area to allow for recovery after the first contingency, minimum generation capacity requirements are established for the area. Assuming that the second-contingency consequences allow for the full 30-minute post-contingency period to be used for restoring the capability of the area to recover from that second contingency, these capacity requirements take into account the mix of internal resources and actions that can respond to the first contingency within 30 minutes. Specifically, in Reserve Adequacy Assessment process and in real-time, the ISO may rely on/use the following types of resources to effect recovery within 30 minutes:

- Spinning reserve of on-line generation
- Non-spinning reserve (expected ICU response)
- Switching load out of the importing area (load swap)[25]
- Load response[26]

[25] This measure, also known as change of transmission topology, is used only for CT.

[26] This resource will be included in the 30-minute response pending the outcome of the Demand Response Reserve Pilot project (DRR Pilot). The DRR Pilot would determine the ability of Demand Resources to meet operational requirements for contingency reserve resources and would investigate more cost-effective communication and telemetry solutions that would allow Demand Resources to participate in reserves markets while maintaining system reliability. The NEPOOL Markets Committee approved DRR Pilot rules on June 8, 2005, and unanimously approved by the Participants Committee on June 24, 2005. A FERC filing will be made in the second half of 2005 and pilot implementation will likely occur in the first half of 2006.

In real-time, the ISO will also rely on emergency actions to aid the 30-minute recovery after the resources above have been exhausted.[27]

Once the import-constrained area's available 30-minute response is determined, it is combined with the area load, interface-transfer limit, and generation-contingency information (if applicable) to determine the area's requirements for minimum generation capacity that satisfy second-contingency requirements. The following calculations are used for the two subregional contingency scenarios:

(3) *Minimum Generation Capacity Requirement for Line–Line Contingency =*

max {0, (*Area Load – Line–Line Contingency Interface Limit* – 30-*Minute Area Response*)},

And

(4) *Minimum Generation Capacity Requirement for Line–Generator Contingency =*

max {0, (*Area Load + Largest Area Generator Contingency – Line–Generator Contingency Interface Limit* – 30-*Minute Area Response*)}[28]

Figure 3 provides a graphical illustration of equations 3 and 4.[29] In Equation 3, the *Line–Line Contingency Interface Limit* reflecting the loss of the two most critical transmission lines serving the area is the most restrictive applicable interface limit.[30] In Equation 4, the *Line–Generator Contingency Interface Limit* reflecting the loss of the most critical transmission line serving the area and the largest generator in the area is the most restrictive applicable interface limit.[31]

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[27] These emergency actions, such as preparing for load shedding, include OP 4 and OP 7 actions.

[28] This equation employs a second-contingency transfer limit based on the loss of the largest source within the affected import area. Also, the area's available reserve capability is part of the capacity requirement. Once a reliable unit commitment is achieved based on area capacity requirements, day-ahead market operators, forecasters and system operators will be able to assess area energy dispatch and available reserve capability and, if needed, ramp out-of-rate energy to ensure that adequate 30-minute response is possible.

[29] Figure 3 for equation 4 (right) adopts a standard definition of augmented load as the sum of load and outages, in this case the sum of load and largest generator contingency in the area.

[30] For the scenario involving loss of the most critical transmission line as the first contingency, the second-contingency interface limit may be substantially less than the first-contingency limit.

[31] It is possible that the loss of the largest area generator, with the resulting loss of that generator's dynamic reactive capability, may require use of a decreased second-contingency interface limit that is lower than the first-contingency interface limit after the line loss. This is applicable only if the interface limit is voltage/reactive.

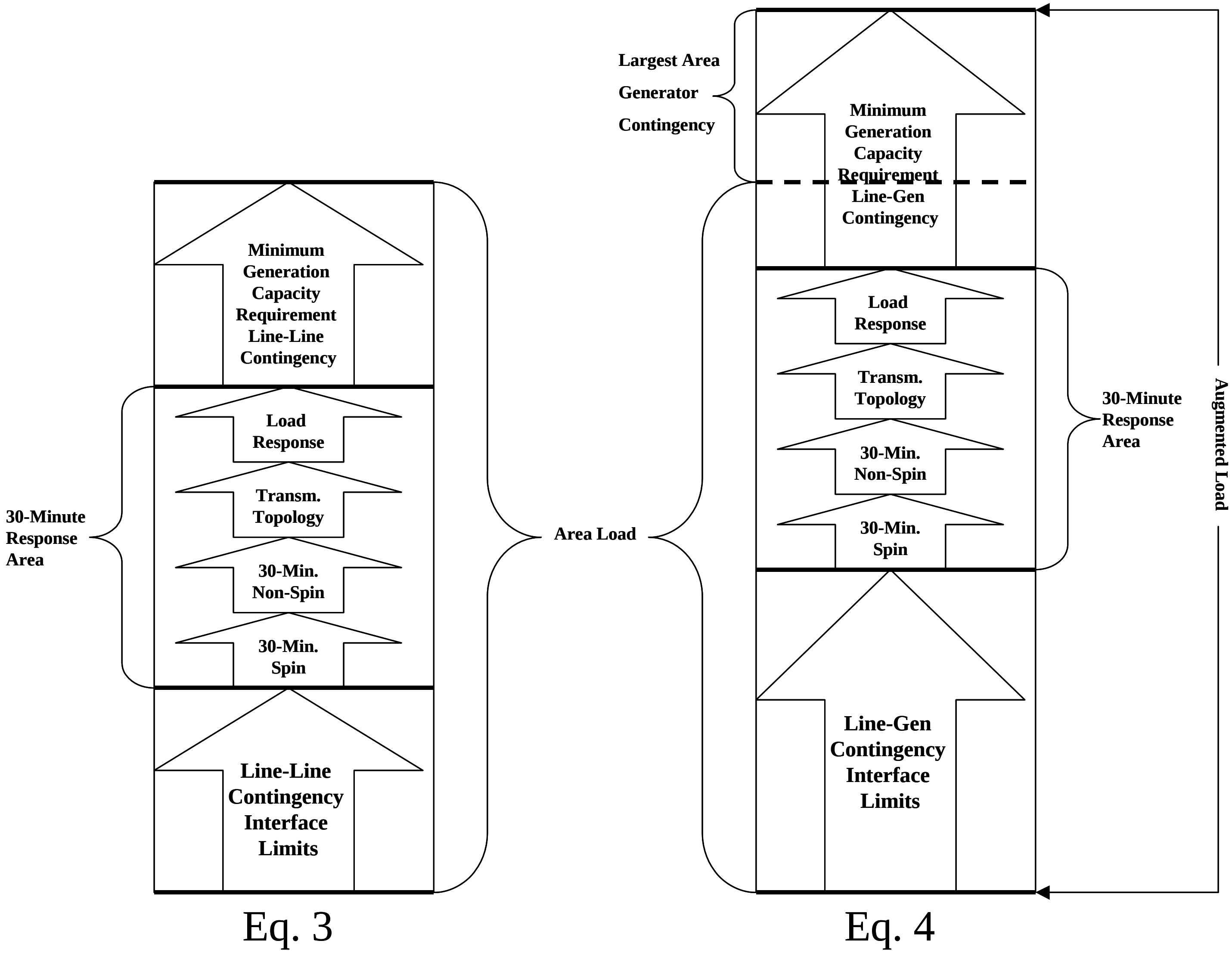


**Figure 3 – Equation 3 (left) and equation 4 (right)**

Example 2: Computation of Minimum Generation Capacity Requirement for Line–Generator Contingency

Assume that a day-ahead New England load of 17,350 MW is forecasted for hour ending 2:00 p.m. For the import-constrained area X, which is approximately 14.4% of New England's load, determine the minimum capacity requirement for this hour assuming the following:

a) To maintain voltage/reactive security in the most restrictive area X, the import limit for the line–generator contingency is 1,800MW.[32]

b) The largest on-line unit is 300 MW.

c) The expected 30-minute area response is estimated to be 140 MW.

Solution:

The import-constrained area X load is 14.4% of 17,350 MW = 2,500 MW.

For protection of area X against the largest line and generator contingency, with the second-contingency transfer limit of 1,800 MW, Equation 4 gives: *Minimum Generation Capacity Requirement for Line–Generator Contingency* = 2,500 MW + 300 MW – 1,800 MW – 140 MW = 860 MW.

Therefore, the day-ahead capacity plan for import-constrained area X should have at least 860 MW of capacity commitment in place for hour ending 2:00 p.m., in addition to the 140 MW of 30-minute response relied upon in the calculation, to provide for the line–generator second contingency.

The calculation shown in this example is carried out for each hour of the day for each of the import-constrained areas. Minimum generation capacity requirements for import areas are modeled in unit-commitment software to ensure that sufficient resources are available for reliable system operations. If an import area's unit commitment, based on a first-contingency New England dispatch, is sufficient to meet minimum generation capacity requirements, then the commitment of "out-of-rate" second-contingency capacity within the area is not required. If the first-contingency dispatch does not satisfy the area's minimum generation capacity requirements, then "out-of-rate" generation must be committed in the area as second-contingency generation. Second-contingency commitments are made only after all first-contingency generators are committed plus available resources for recovering from a first contingency have been exhausted. Also note that these requirements are highly dependent upon the level of first-contingency generation in an area. Modeling minimum generation capacity requirements in the unit-commitment software is accomplished by using interface proxy limits.

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[32] A second-contingency import limit of 1,800 MW means that with actual imports of 1,800 MW or less, the system can withstand the second worst line–generator contingency that could impact the XYZ area without violating the applicable reliability criteria, in this case, minimum voltage levels.

### 4.3.2 Interface Proxy Limits for Second Contingency

An interface proxy limit is a different way of representing an area's second-contingency requirement. The distinction between a second-contingency proxy limit and a second-contingency interface transfer limit is that the second-contingency interface transfer limit is a physical limit while the proxy limit also includes the impact of available 30-minute actions within the area. The ISO uses the proxy limits to ensure compliance with subregional reliability at the interface level.

The ISO employs interface proxy limits for second contingencies in real-time operations as a way to set the interface-loading limit relative to the maximum flow for which 30-minute area recovery can be maintained. Proxy limits are also used in the Day-Ahead and Reserve Adequacy Analysis algorithms. By utilizing the proxy limits, the Day-Ahead and Reserve Adequacy Analysis unit-commitment algorithms provide for sufficient on-line capacity to not only withstand the subregion first-contingency loss but to also restore the subregion to a state from which it can withstand the second contingency within 30 minutes after the first contingency occurs. Note that the proxy limits may differ in day-ahead and real-time markets, based on the difference between assumed and actual system conditions.

The following equations define an interface's proxy limit for the first/second contingency scenarios of either loss of two transmission lines or loss of a transmission line followed by loss of the largest area generator:

(5) *Interface Proxy Limit for Line–Line Contingency =*
*Line–Line Contingency Interface Limit + 30 Minute Area Response,*

and

(6) *Interface Proxy Limit for Line–Generator Contingency =*
*Line–Generator Contingency Interface Limit* **-** *Largest Area Generator Contingency +*
*30-Minute Area Response,*

where the *Line–Line* or *Line–Generator Contingency Interface Limit* are the same as in Equation 3 and Equation 4 above.

Note that the interface proxy limits are simply a reformulation of the capacity requirements outlined earlier. Substituting Equation 5 into Equation 3, and Equation 6 into Equation 4, we obtain:

(7) *Minimum Generation Capacity Requirement for Line–Line Contingency* =
max {0, (*Area Load – Interface Proxy Limit for Line–Line Contingency*)},

and

(8) *Minimum Generation Capacity Requirement for Line–Generator Contingency =*
max {0, (*Area Load – Interface Proxy Limit for Line–Generator Contingency*)}

Figure 4 provides a graphical illustration of equations 7 and 8 (cf. Figure 3.)

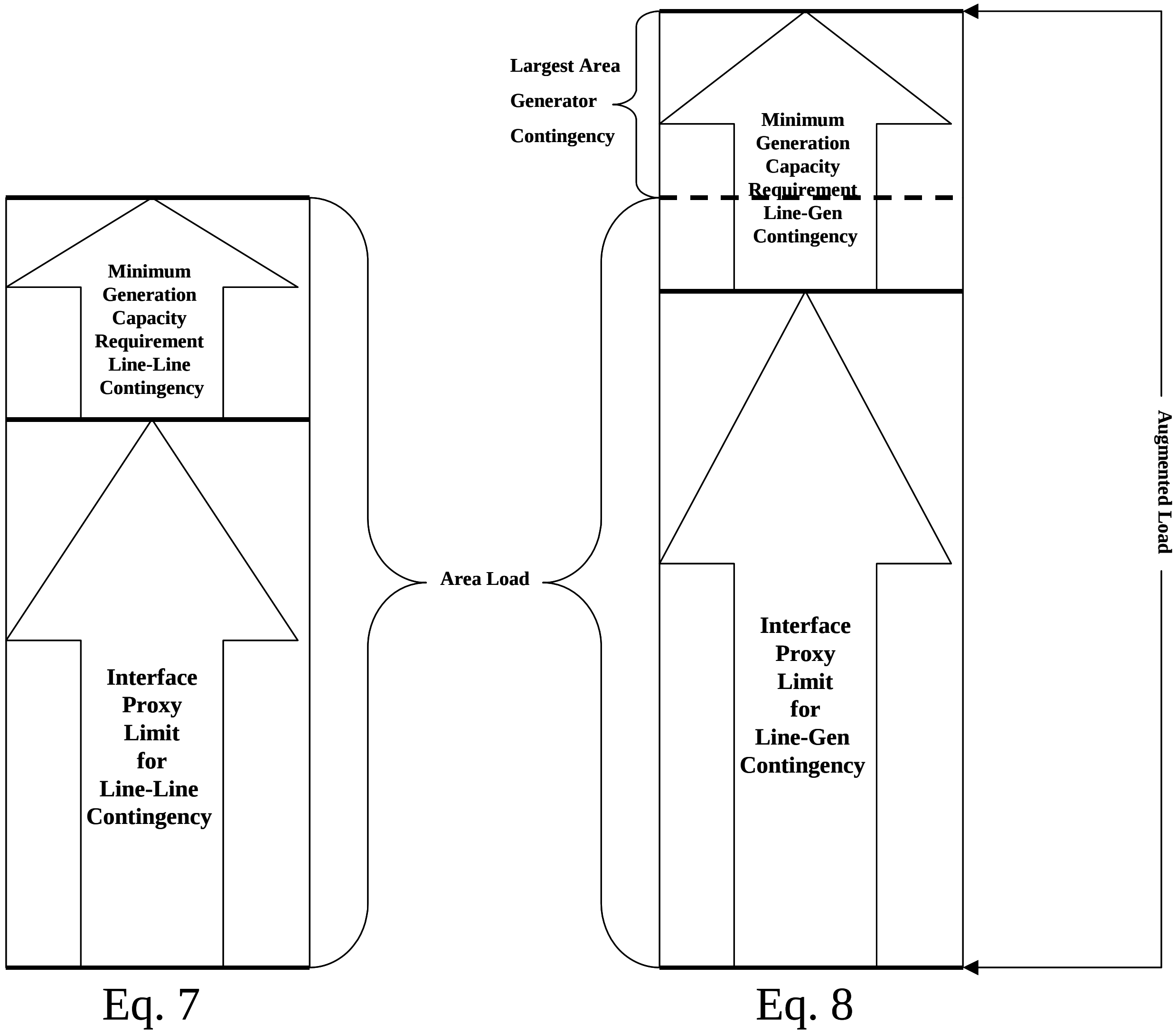


**Figure 4 - Equation 7 (left) and equation 8 (right)**

Example 3: Computation of Proxy Limits and Minimum Generation Capacity Requirement

Assume that a day-ahead New England load of 17,350 MW is forecasted for hour ending 2:00 p.m. For the import-constrained area X, which is approximately 14.4% of New England's load, determine the proxy interface limits and the minimum capacity requirement for this hour assuming the following:

a) The line–line limit is 1,180 MW, and the line–generator limit is 1,800 MW.

b) The largest on-line area X generator is expected to be at 300 MW.

c) The 30-minute area X response for line–line contingency is 310 MW; the response for the line–generator contingency is 140 MW.[33]

Solution:

From Equation 5:

Interface Proxy Limit for Line–Line Contingency =

1,180 MW + 310 MW =1,490 MW;

and from Equation 6:

Interface Proxy Limit for Line–Generator Contingency =

1,800 MW - 300 MW + 140 MW = 1,640 MW.

The proxy limit for a line–line contingency, which is the maximum proxy-interface loading permissible to ensure the availability of line–line contingency protection for the hour in this example, is more restrictive. This results in a higher minimum generation capacity requirement. With an area X import-constrained load of 2,500 MW (14.4% of 17,350 MW), Equation 7 shows:

Minimum Generation Capacity Requirement for Line–Line Contingency =
max {0, (2,500 MW – 1,490 MW)} = 1010 MW;

and from Equation 8:

Minimum Generation Capacity Requirement for Line–Generator Contingency =
max {0, (2,500 MW – 1,640 MW)} = 860 MW,

which is the same as the answer in Example 2, given the identical assumptions.

[33] The larger 30-minute area response for line–line contingency is due to the additional action of contracted load shedding, allowed if the interface limit is thermal.

Therefore, since the line–line contingency produces the greater capacity requirement for area X, 1,010 MW of generation capacity will be needed for this hour for second-contingency protection. The decision to select the generators that will comprise the 1,010 MW of area X capacity will be affected by a number of factors, such as offer data, generator operating characteristics, and generator availability.

# Section 5
# Fulfillment of Requirements: Processes and Tools

This section describes the processes and tools that implement the ISO's reliability criteria and result in the reliable operation of the grid. The section concludes with a brief description of the software used to implement each procedure.

## 5.1 Overview

Reliability analysis begins the day prior to the operating day, starting with the morning load forecast, which is used in the GRT analysis described above. The proxy limits, computed in the GRT analysis, along with generators needed for voltage support the next day become inputs into the day-ahead market clearing process. This process matches day-ahead supply and demand with a least-cost energy production solution. The process produces the day-ahead schedule of physical resource dispatch, including reliability commitments. The day-ahead schedule becomes an input to the Reserve Adequacy Analysis process along with revised offers received during the re-offer period. These revised offers may include self-scheduled generation. The RAA uses the updated information to develop the reliability commitments for the operating day. This occurs before the start of the operating day. "RAA" also is used to describe a similar, ongoing process that provides commitment updates throughout the operating day.

The timeline in Figure 5 details the sequence of procedures used to ensure reliability for the operating day. Following this timeline, we review the sequence of processes and procedures used to ensure a reliable real-time commitment, beginning with the 10:00 a.m. day-ahead load forecast through the real-time updating of the current operating plan.

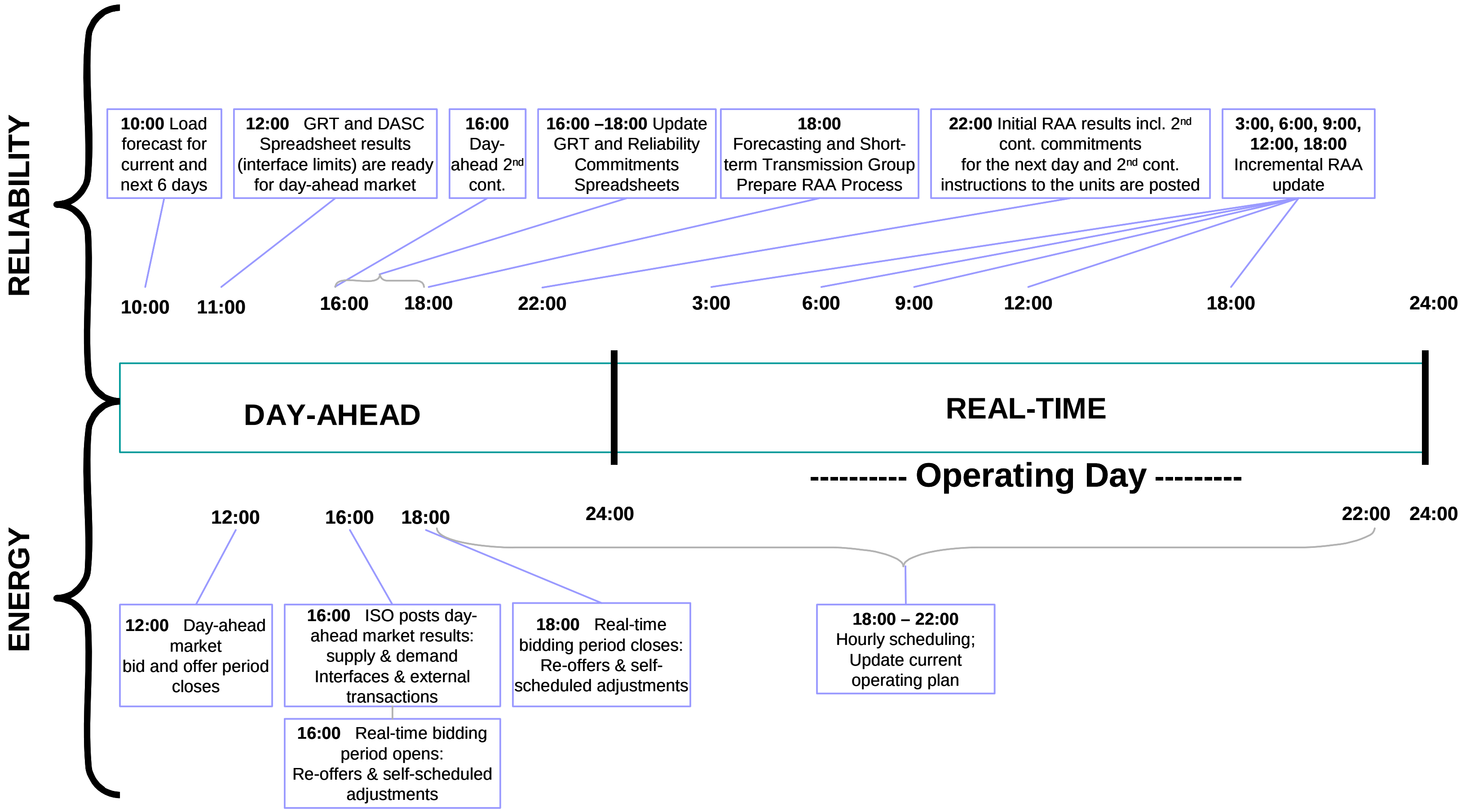


**Figure 5** Reliability actions in the day-ahead and real-time market

### 5.1.1 Load Forecasts

The load forecast is fundamental to the assessment of interface limits and the reliability requirements for the operating day. While load forecasts may project load up to seven-days in advance, the first forecast, which normally has a large influence on the unit commitment for a given day, is developed at 10:00 a.m. the day prior to the operating day. The ISO periodically updates this load forecast throughout both the day-ahead and the operating day. This forecast is a primary input to the GRT Analysis.

### 5.1.2 GRT Analysis and Spreadsheet

The basic tool for conducting the GRT analysis is the GRT spreadsheet, developed each day for the 12:00 noon day-ahead market planning meeting. The spreadsheet calculates first-contingency proxy limits for export-constrained regions and first- and second-contingency interface proxy limits and minimum generation requirements for import-constrained regions using the formulas in the previous section.[34]

Critical daily input to the GRT spreadsheet includes the following:

- Forecasted hourly New England load
- Importing/exporting area forecast load as a percentage of New England system load
- First-contingency area interface-transfer limits

It also includes the following inputs, as applicable:

- Second-contingency area interface-transfer limits
- Area's largest generator contingencies
- Area's available/effective fast-start generators (ICUs);
- Area load-relief or ISO Operating Procedure 4, *Operation during a Capacity Deficiency* (OP 4) actions[35]
- Acceptable area load shed amounts
- Estimated area 30-minute spinning reserves

From these inputs, the following outputs are determined and displayed:

- Maximum allowable area generation (energy)
- Minimum required area generation (energy)

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[34] Interface limits are inputs to the spreadsheet and are determined outside of the GRT spreadsheet utilizing the EMS Powerflows or PSSE. Additional limits are captured for imports from and exports to New York.

[35] http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html

- Day-ahead area proxy interface-transfer limits

An initial version of the GRT spreadsheet is created for use in the day-ahead market process. An updated version of the spreadsheet is created by 18:00 each day for use in the RAA.

### 5.1.3 Day-Ahead Supplemental Commitment Sheet

Specific generators that are needed to fulfill a portion of the area generation requirements, determined by the GRT analysis for the following operating day, are identified on the Day-Ahead Supplemental Commitment (DASC) sheet. These generators, identified using operating guidelines developed in the off-line studies, are needed for voltage support. Units needed for second-contingency support are produced by the day-ahead market solution that respects the second-contingency proxy limits from the GRT spreadsheet. The distribution support is an input into the RAA process directly. Like the GRT spreadsheet, the DASC sheet, which is used in day-ahead market, is updated for use in the RAA after the day-ahead market clears.

### 5.1.4 Reliability Assessment and Commitment in the Day-Ahead Market Process

The Day Ahead Energy Market scheduling process uses the load forecast, the DASC sheet, and the GRT spreadsheet to ensure that reliability criteria are met in the day-ahead market.

First, the ISO determines systemwide reserve requirements for the operating day prior to clearing the day-ahead market. The day-ahead market unit commitment and dispatch software tools use systemwide reserve requirements to ensure that these requirements are met.

Generators on the DASC sheet are flagged as voltage-support resources. They are manually committed in the day-ahead market clearing process and are the inputs in the commitment and dispatch software programs.

The day-ahead market commitment and dispatch software uses the interface limits developed in the GRT spreadsheet. If a first-contingency interface limit binds because there is too little or too much first-contingency generation in an area, price separation will occur between the constrained area and the remainder of the region. Area generation is increased in import-constrained areas or decreased in export-constrained areas.

Second-contingency proxy limits from the GRT analysis also are used where applicable and can have the same effect as the first-contingency limit discussed above. Units committed solely due to binding constraints based on these proxy limits are identified as daily second-contingency resources in the day-ahead market. The ISO identifies these units following the approval of the day-ahead schedule. It then analyzes the unit commitment and determines which of the generators would not have been committed without the use of the proxy limit and flags those generators for second-contingency support.

### 5.1.5 GRT Update Post-Day-Ahead Market

The GRT spreadsheet is updated after the 16:00 posting of the day-ahead market results. The day-ahead market results are used as an input for the second iteration of the GRT analysis. This information about unit commitment influences the calculation of interface limits in the next iteration of the GRT analysis, as we have better knowledge about largest area generator contingencies and better estimate of

30-minute spinning reserve. This update of the GRT spreadsheet also includes any revisions to the next-day load forecast or changes in transmission topology. This next iteration of GRT analysis, which takes place between 16:00 and 18:00, serves as an input to the RAA process.

### 5.1.6 Reserve Adequacy Analysis

Following the posting of the day-ahead schedule, the ISO performs the RAA to determine if additional generators must be committed to address expected real-time reliability requirements that were not addressed through the day-ahead schedule or by unit self-schedules during the re-offer period.[36] Start-up orders resulting from the RAA process may be cancelled if forecast conditions change or if additional generators self schedule during the day. The RAA takes into account offers received during the re-offer period and the second iteration of the GRT analysis. The RAA may commit generators to meet regionwide reliability needs, first- or second-contingency coverage, voltage, or distribution needs. Generators are identified according to their commitment cause.

The RAA process begins at 18:00 and lasts until 22:00, concluding with publication of the Current Operating Plan (COP). Analyses and additional commitments are conducted in the following order:

1. Additional voltage-control resources ("Voltage Up" or "VU") during light-load periods. Conditions for commitment are based on the forecasted load and ISO voltage guides. These resources may provide operating reserve capability that can contribute to meeting the regionwide capacity-reserve requirements. These resources are flagged as 'VU' units.

2. Concurrent with VU, distribution resources, if requested by transmission owners. Distribution resources also may contribute to meeting the regionwide capacity-reserve requirements. These resources are flagged as 'distribution' units.

3. Resources to ensure the protection against the first contingencies for local, export- and import-constrained areas. These resources are not flagged.

4. Second-contingency resources to meet second contingencies in import-constrained areas. These resources are flagged as 'daily second-contingency' units.

5. Pool-wide operating-reserve requirement to ensure that all scheduled load is served in real-time and the pool-wide first and second contingencies are covered. These resources are not flagged.

### 5.1.7 Updates to the Reserve Adequacy Analysis

The RAA is an ongoing process that begins with the solution of the day-ahead market for the next operating day and ends at the conclusion of the operating day. After the initial version of the Current Operating Plan is published at 22:00 on the day before the operating day, the ISO performs an hourly assessment and publishes periodic updates to the Current Operating Plan.

The ISO's Hourly Capacity Analysis application combines data from several sources to provide a comprehensive assessment of the capacity available versus the capacity needed to meet expected demand

[36] The Day Ahead commitments often do not address reliability requirements in Real-Time. Some of the reasons are the differences between load forecast vs. bid load, virtual transactions, and delisted units not offering into Day-Ahead market.

and reserve requirements for the remainder of the operating day. It calculates the capacity surplus or deficiency within the control area and highlights hours where a deficiency is forecast. The application is rerun every hour with the following latest data:

- Hourly forecast demand
- Hour forecast reserve requirement, including the following elements:
    - 10-minute spinning requirement (100% of largest single contingency)
    - 30-minute requirement (50% of second largest single contingency)
    - replacement reserve requirement (25% of second largest single contingency)
- Current Operating Plan for internal generating resources
- Generator re-declarations
- Generators output limitation due to transmission outage
- Generator output limitation when in start-up ramp (not yet released for dispatch at Economic Minimum (EcoMin))
- Generators that are unavailable due to their notification and start-up times
- Limited energy generator (LEG) limitations[37]
- The real-time fixed and dispatchable external purchase and sale transactions that have checked out with the neighboring control area
- Fixed and dispatch pumped-storage demand

The application also performs an hourly Minimum Generation Emergency Assessment for which it compares the minimum supply megawatts (internal generation and fixed external transactions) against the ISO's hourly forecast demand (MW) plus available additional pumped-storage demand (MW) plus dispatchable external sales transactions (MW). The application highlights hours where an excess of supply is forecast.

## 5.2 Capacity Commitment and Security Analysis Software

This subsection highlights the various software components (tools) used for day-ahead and real-time energy and capacity commitment and security analysis. To settle the day-ahead market and perform security-constrained dispatch for real-time operations, the ISO uses reliability scheduling and commitment (RSC); scheduling, price, and dispatch (SPD); simultaneous feasibility test (SFT); and unit

[37] Typically hydro and pump storage.

dispatch system (UDS) software. The inputs, frequency of execution, and, in some cases, the objective function, differ across uses between the day-ahead market and RAA.

### 5.2.1 Reliability Scheduling and Commitment

The RSC software used in day-ahead market clearing develops a least-cost unit commitment solution that satisfies the day-ahead hourly demand and reserve requirements for the next operating day's 24 -hour period. Any required de-commitment of generators in exporting areas will be identified through export limits in subsequent day-ahead software components.

### 5.2.2 Scheduling, Price, and Dispatch

The scheduling, price, and dispatch software takes the RSC output as an input and uses available resources to satisfy demand, reserve requirements, and transmission constraints at a minimum cost in the day-ahead market and in the RAA on an hourly basis. In real-time, SPD is used every five minutes to calculate locational marginal prices. Interface-transfer limits also are modeled and respected along with any local generator constraints. Operators have the option of performing manual de-commitments of resources to address minimum generation emergency conditions to maintain system reliability.

### 5.2.3 Simultaneous Feasibility Test and Unit Dispatch System[38]

The day-ahead SFT performs a security evaluation on the hourly SPD solution for the day-ahead market. Thermal system performance is assessed via both a full and linear DC network model and a contingency analysis that evaluates a full set of contingency criteria. All scheduled generation and load must be feasible within the capability of the transmission system. If the market successfully passes the tests, the day-ahead market clears and prices are established. If the SFT tests fail, iterative re-runs of SPD and SFT are necessary.

In real-time, SFT takes the form of Real-Time Contingency Analysis (RTCA). This application performs all the functions of SFT, but uses real-time state-estimated data and executes every five minutes. The RTCA constraints then are activated in the constraint-logger application (CLOGGER) and then fed into unit dispatch system software. UDS software produces real-time desired dispatch points (DDPs) and dispatch rates that are communicated to generators.

[38] SPD and SFT programs are identical in day-ahead and real-time. The only difference is the input data (day-ahead and real-time data sets.)

# Section 6
# Fulfillment of Requirements in Import-Constrained Areas—Case Studies

Day-ahead planning and real-time operations must act to ensure that an adequate recovery from first and second contingencies is possible. This is particularly so in import-constrained areas of New England where existing resources do not inherently provide for the acceptable recovery from a first contingency and the restoration of the ability to withstand a second contingency within the 30-minute criteria allotment and where the consequences of not protecting for a second contingency would jeopardize the bulk power system. Two case studies are presented in this section that demonstrate the fulfillment of reliability requirements. At present, only the following import areas in New England require analysis of their ability to recovery from second contingency within 30 minutes:

- Boston/Northeast Massachusetts (NEMA/Boston)
- Connecticut (CT)
- Southwest Connecticut (SWCT)
- Norwalk/Stamford (NWST)

The two case studies demonstrate how reliability requirements determine the commitment of additional resources in the import-constraint areas.

## 6.1 Reliability Analysis in NEMA/Boston

The first example demonstrates the reliability analysis in NEMA/Boston import-constrained area for a particular hour and is summarized in Table 3.

**Table 3 Reliability Analysis in NEMA/Boston**

| | Availability | 1st Line | Line-Gen | Line-Line |
|---|---|---|---|---|
| **1) Area Load** | | 4405 | 4405 | 4405 |
| **2) Import Limit** | | 3700 | 3700 | 2500 |
| **3) Scheduled Generation** | 1127 | 1127 | 427 | 1127 |
| **4) Apparent Transfer (1-3)** | | 3278 | 3978 | 3278 |
| **5) Initial Transfer Surplus/Deficiency (2-4)** | | 422 | -278 | -778 |
| **6) On-Line 30 Minute Response** | | 0 | 0 | 0 |
| **7) Off-Line 30 Minute Response** | 74 | 0 | 74 | 74 |
| **8) Load Shed for 2nd Line** | 400 | 0 | 0 | 400 |
| **9) Adjusted Transfer Surplus/Deficiency (5+6+7+8)** | | 422 | -204 | -304 |
| **10) Generation Available for Supplemental Commitment** | 1620 | 0 | 0 | 565 |
| **11) Transfer Surplus/Deficiency (9+10)** | | | | 261 |
| **12) Load Swap, OP4, OP7 Actions Required** | | 0 | 0 | 0 |

The scenario is based on the loss of Line No. 337 (first line) and the subsequent loss of the largest 700 MW generator (line–gen) or second line, Line No. 394 (line–line). The following steps detail the line-by-line calculation.

1. The area load for a chosen hour in this analysis is 4,405 MW.

2. The GRT spreadsheet analysis shows that the area-transfer limit for the largest line contingency is 3,700 MW. For the line–line (second line largest contingency), the transfer limit decreases to 2,500 MW. The most restrictive limits in NEMA/Boston area are thermal.[39]

3. Area generation from the Current Operating Plan is equal to 1,127 MW. The largest area generator contingency is 700 MW, reducing the available generation to 427 MW for the line–gen contingency.

4. Apparent transfer shows how much power would need to be imported under the three scenarios to satisfy demand. It is equal to the real-time load minus the available generation within the area (line 1 minus line 3).

5. Transfer surplus/deficiency compares the area-transfer limits against the required MW transfers into the area (line 2 minus line 4). Additional resources within the area are not required to sustain the first contingency as the area-Transfer limit exceeds the apparent transfer. However, this is not the case for the second contingency that leads to a transfer deficiency of 278 MW due to a loss of area-internal generator in the line–gen case and to transfer deficiency of 778 MW due to the diminished import capability in the line–line

[39] See Table 2.

case. The subsequent analysis concentrates on additional resources needed to protect against a second contingency.

6. There are no on-line 30-minute response resources available for the given hour.

7. Available off-line 30-minute resources total 74 MW.

8. Load shed[40], applicable to line–line thermal-limit contingency, is equal to 400 MW.

9. With these additional resources, the deficiencies are reduced to 204 MW in the line–gen case and to 304 MW in the line-–line case (line 5 plus line 6 plus line 7 plus line 8.) Therefore, the line-–line case is the most restrictive and requires the largest commitment of second-contingency resources.

10. The additional available generation within the area is 1,620 MW. An analysis of system requirements determines that committing a single unit with a SCC of 565 MW is the most economical solution to cover the line–line transfer.

11. With this supplemental commitment, the transfer deficiency of 304 MW becomes a transfer surplus of 261 MW.

12. Since this supplemental commitment results in transfer surplus for the worst second contingency, the load swap, OP 4, and Operating Procedure 7, *Action in an Emergency*, (OP 7) actions are not required.[41]

## 6.2 Reliability Analysis in Connecticut

The second example demonstrates the reliability analysis in the Connecticut import-constrained area and is summarized in Table 4.

[40] Consistent with operating criteria, actions such as load shedding can be utilized for post-second contingency response provided that post-second contingency line loadings are within acceptable emergency limits and operators have time to implement the load shedding.

[41] *See:* <http://www.iso-ne.com/rules_proceds/operating/isone/op7/index.html>.

**Table 4 Reliability Analysis in Connecticut**

| | Availability | 1st Line | Line-Gen | Line-Line |
|---|---|---|---|---|
| **1) Area Load** | | 5348 | 5348 | 5348 |
| **2) Import Limit** | | 2500 | 2315 | 1450 |
| **3) Scheduled Generation** | 3027 | 3027 | 1867 | 3027 |
| **4) Apparent Transfer (1-3)** | | 2321 | 3481 | 2321 |
| **5) Initial Transfer Surplus/Deficiency (2-4)** | | 179 | -1166 | -871 |
| **6) On-Line 30 Minute Response** | 0 | 0 | 0 | 0 |
| **7) Off-Line 30 Minute Response** | 566 | 0 | 566 | 566 |
| **8) Load Shed for 2nd Line** | 535 | 0 | 0 | 535 |
| **9) Adjusted Transfer Surplus/Deficiency (5+6+7+8)** | | 179 | -600 | 230 |
| **10) Generation Available for Supplemental Commitment** | 2738 | 0 | 728 | 0 |
| **11) Transfer Surplus/Deficiency (9+10)** | | | 128 | |
| **12) Load Swap, OP4, OP7 Actions Required** | | 0 | 0 | 0 |

This scenario is based on the first largest line contingency, consisting of the loss of Line No. 398 and Line No. 321 (first line), and the subsequent loss of the largest 1,160 MW generator (line–gen), or second largest line–line contingency, which consists of the loss of Line No. 395 and Line No. 330 (line–line).[42] The following steps detail the line-by-line calculations.

1. The area load for a chosen hour in this analysis is 5,348 MW.

2. The GRT spreadsheet analysis shows that the area-transfer limit for the largest line contingency is set by the voltage limit and is equal to 2,500 MW. For the line–gen contingency, the most restrictive transfer limit is voltage and equal to 2,315 MW. For the line–line contingency, the most restrictive transfer limit is thermal and equal to 1,450 MW.

3. Area generation from the Current Operating Plan is equal to 3,027 MW. The largest area generator contingency is 1,160 MW, reducing the available generation to 1,867 MW for the line–gen contingency.

4. Apparent transfer shows how much power would need to be imported under the three scenarios to satisfy demand. It is equal to the real-time load minus the available generation within the area (line 1 minus line 3.)

5. Transfer surplus/deficiency compares the area-transfer limits against the apparent transfers into the area (line 2 minus line 4.) Additional resources within the area are not required to sustain the first contingency as the area-transfer limit exceeds the apparent transfer. However, this is not the case for the second contingency that leads to a transfer

[42] Note that the first largest line contingency may consist of the simultaneous loss of two physically related lines.

deficiency of 1,166 MW due to a loss of area-internal generator in the line–gen case and to transfer deficiency of 871 MW due to diminished import capability in the line–line case. The subsequent analysis concentrates on additional resources needed to protect against second contingency.

6. There are no on-line 30-minute response resources available for the given hour.

7. Available off-line 30-minute resources total 566 MW.

8. Load shed, applicable to a line–line thermal-limit contingency, is equal to 535 MW.

9. With these additional resources, the deficiency is reduced to 600 MW in the line–gen case and eliminated. It becomes a surplus of 230 MW in the line–line case (line 5 plus line 6 plus line 7 plus line 8.) Therefore, the line–gen case is the most restrictive and also requires the additional commitment of second-contingency resources.

10. The additional available generation within the import-constrained area is 2,738 MW. Out of this amount, the minimum amount of generation that can be committed to cover the line–gen transfer deficiency is 728 MW. An analysis of system requirements determines that committing a single unit with a SCC of 728 MW is the most economical solution to cover the line–gen deficiency.

11. With this supplemental commitment, the transfer deficiency of 600 MW becomes a transfer surplus of 128 MW.

12. Since this supplemental commitment results in a transfer surplus for the worst second contingency, the load swap, OP4, and OP7 actions are not required.