NEW ENGLAND 2005 TRIENNIAL REVIEW OF Resource Adequacy

ISO New England Inc.

Approved by RCC on November 29, 2005

1.0 EXECUTIVE SUMMARY

1.1. MAJOR FINDING

This report was prepared to satisfy the compliance requirements for a Triennial Review of the New England Control Area's Resource Adequacy as established by the Northeast Power Coordinating Council (NPCC). The guidelines for the review are specified in the NPCC Document B-8 entitled *Guidelines for Area Review of Resource Adequacy* (Revised: June 28, 2001)[1].

This review used the ISO Reliability Model, a multi-area reliability model developed by ISO New England (ISO-NE) staff, to assess resource adequacy of the New England bulk power generation system for the study period of 2006-2010. The New England system was modeled as 13 interconnected sub-areas. The transmission interface transfer capabilities between these sub-areas have been determined based on the reliability criteria established by both ISO-NE and NPCC. The sub-area representation of the New England system is consistent with New England's Regional System Plan 2005 (RSP05).

This review shows that New England will meet the NPCC Resource Adequacy Criterion for the study period from 2006 to 2009, inclusive, under the expected resource and load forecasts, and the projected transmission system conditions . New England will need an additional 170 MW of resources starting in 2010.

Sensitivity scenarios with the delay of planned transmission upgrade projects and high load forecasts are also investigated. These results show that under the high load forecast, New England will have adequate resources to meet its reliability criterion for the period 2006 through 2008, and that approximately 800 MW of additional resources will be needed starting in 2009, and increasing to 1,530 MW in 2010. If all the planned transmission upgrade projects are delayed beyond the study period, New England will not be able meet the 0.1 days per year Loss of Load Expectation (LOLE) criterion starting in 2008 under the high load forecast, and in 2009 under the reference load forecast.

ISO-NE RSP05 has identified that the most reliability effective locations for future resource additions are in the order of Connecticut states, Boston area, and central and western Massachusetts.

The New England bulk power system has been deregulated since 1999. This means that the installation of generating resources is market driven. Incentives to promote new generation entries into the market will depend on market signals. ISO New England provides market signals regarding resource needs through the annual Regional System Plan (RSP). The 2005 RSP was approved by the ISO New England Board of Directors on October 21, 2005. In that plan, ISO New England identified the year, the location and the amount of resources and transmission projects needed to meet system reliability. To provide additional incentives to resources to site at locations where they are needed the most, in 2004, ISO-NE has filed with the Federal Energy Regulatory Commission (FERC) a proposal to implement a Locational Installed

[1] http://www.npcc.org/PublicFiles/Reliability/CriteriaGuidesProcedures/B-08.pdf

Capacity (LICAP) market. The LICAP market is aimed to provide incentives to resources to be installed in the New England system where they are needed the most. In August 2005, FERC issued an order delaying the implementation of the LICAP market no earlier than October 1, 2006. In the event that market signals do not promote adequate generation or demand response resource installations, the ISO New England has the ability to issue special Request for Proposals (RFP) for generating or demand response resources to meet system reliability. At present, there is an emergency RFP in place for southwest Connecticut where over 250 MW of resources have been purchased and installed through this RFP for use during the summer months to support system resource needs in New England. This program is targeted to end in 2008, when transmission upgrades to southwest Connecticut is expected to be in-service. To address fuel supply concerns this winter of 2005/06, ISO New England has filed with the FERC to implement a Demand Response Winter Supplemental Program covering December 1, 2005 through March 31, 2006. This program is intended to enroll up to 450 MW of demand response programs that will be used to mitigate capacity needs during this coming winter period. To preserve existing generating resource from deactivation or retirement, the current procedures in New England require that generating units obtain approval from ISO New England before they are allowed to retire or deactivate. ISO New England can enter into financial Reliability Must Run agreements with generating resources that are needed for system reliability.

Although not modeled in this Review, a total of 14 new generation projects (about 1,900 MW) have been proposed and approved for interconnection in New England. These new resources are candidates to address potential resource adequacy issues.

1.2. Summary of Major Assumptions and Results

Table 1 shows the major assumptions used in this review.

Table 1 Major Assumptions

Assumptions	Description
Reliability Criterion	NPCC Criterion: LOLE of 1 day in 10 years
Load Model	Weekly peak load distribution
Reliability Model	ISO Reliability Model
Unit Availability	EFORd: 5 year average (2000 to 2004)
Tie Benefits	Assumed 2,000 MW. Tie Benefits assumption encompasses entire study period 2006 – 2010, inclusive.
Emergency Operating Procedures (Load Relief, Voltage Reduction)	Modeled
New Generating Capacity Additions	8.4 MW
Generating Capacity Retirements	0 MW
Generation Capacity Deactivations	219 MW (2006 – 2010)
Reflecting Internal Transmission Constraints	Yes - Based on various transmission studies and consistent with New England RSP05 studies.

Table 2 and Table 3 below summarize the results of this study. The Base Case is based on all the major assumptions listed in Table 1, and assumes all the planned transmission upgrade projects will be completed as expected. The Sensitivity Case assumes that all the planned transmission upgrade projects will be delayed beyond the study period. The Loss of Load Expectation (LOLE) values in these tables are expressed in days per year. An LOLE of 0.1 days per year or less satisfies the resource adequacy criterion.

Table 2 LOLE Results for the Base Case

Year	LOLE Based On Reference Load Forecast (Days per Year)	LOLE Based On High Load Forecast (Days per Year)
2006	0.0196	0.0256
2007	0.0276	0.0499
2008	0.0447	0.0977
2009	0.0976	0.2379
2010	0.1440	0.3970

Table 3 LOLE Results for the Sensitivity Case

Year	LOLE Based On Reference Load Forecast (Days per Year)	LOLE Based On High Load Forecast (Days per Year)
2006	0.0281	0.0347
2007	0.0406	0.0684
2008	0.0598	0.1251
2009	0.1401	0.3181
2010	0.1996	0.5171

The results in Table 2 and Table 3 show that New England has enough resources to meet the NPCC Resource Adequacy Criterion through 2009 under the reference load forecast and projected topology of the transmission system. Additional resources of approximately 170 MW under the Base Case will be needed starting in 2010. Under the Sensitivity Case of higher than expected load growth, New England will need additional resources starting in 2009 – approximately 800 MW in 2009, and 1,530 MW in 2010. If all the planned transmission upgrades projects can not be completed during the study period, New England will violate the 0.1 days per year LOLE criterion starting in 2009 under the reference load forecast, and in as early as 2008 under the high load forecast.

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3.0 INTRODUCTION

Since January 31, 2005, ISO-NE has begun its operation as a Regional Transmission Organization (RTO), assuming broader authority over the day-to-day operation of the region's transmission system and possessing a greater level of independency to effectively manage the region's bulk electric power system and competitive wholesale electricity markets. As the RTO, ISO-NE continue to perform all of its past responsibilities and also exercise day-to-day operational control of the transmission system under agreements with existing transmission companies. ISO-NE is now the single point-of-control to effectively maintain reliability and preserve the integrity of the bulk power system on a daily basis and in emergency situations. Under the RTO structure, ISO-NE has the authority to file proposed market rule changes with Federal Energy Regulatory Commission, while working closely with stakeholders. ISO-NE will also enhance the regional system planning process that identifies New England's electricity needs and promotes infrastructure improvements where they are most needed.

The purpose of this report is to review the resource adequacy in New England as required by NPCC. As part of its Reliability Assessment Program, NPCC conducts resource adequacy reviews of its members' areas to ascertain whether or not each area will have enough resources to meet the NPCC Resource Reliability Criterion. These resource adequacy reviews are currently done on a triennial basis.

In this review, and consistent with both the last comprehensive triennial review and New England's RSP05, the New England system was modeled as 13 interconnected sub-areas, with the transmission interface transfer capabilities between these sub-areas having been determined based on the reliability criteria established by both ISO-NE and NPCC. The ISO Reliability Model, a multi-area reliability model developed by ISO-NE staff, was used for conducting this review of resource adequacy.

This report compares current and previous resource plans and analyzes the adequacy of New England's resources based on the reference and high load forecasts for the period 2006 to 2010.

3.1. PREVIOUS TRIENNIAL REVIEW OF NEW ENGLAND'S RESOURCE ADEQUACY

The NPCC Reliability Coordinating Committee approved the previous New England Triennial Review of Resource Adequacy in December 2002. The findings of that review showed that New England had adequate resources to meet the NPCC Reliability Criterion for the period 2003 through 2007 under both the reference and high load forecasts.

3.2. COMPARISON OF CURRENT AND PREVIOUS RESOURCE PLANS

The previous Triennial Review of New England's Resource Adequacy was based on the 2002 New England Load Forecast, which projected summer peak loads with a compound annual load growth rate of 1.38 percent for the period 2003 to 2007. The 2005 New England Load Forecast projects summer peak loads[2] with a compound annual load growth rate of 1.40 percent for the

[2] Peak Load is adjusted to account for the impacts of Demand Side Management (DSM) Programs and the New England Participant recognized non-utility capacity, which is netted from the load forecast. The reference load forecast used is found within the "2005 *Capacity, Energy, Loads and Transmission Report*", dated April, 2005 (CELT). A description of the DSM components is given in Appendix A.1.5.

period 2006 to 2010. The comparison of these two load forecasts is shown in Figure 1, which indicates that the reference annual peak loads used in this Review are higher than those in the 2002 Review. For the years of 2006 and 2007 that both Reviews cover, this Review's numbers are about 1,200 MW higher than that in the 2002 Review. The difference is mainly due to the result of the updated load forecast parameters used for the forecast process, including both economy and weather, and an increasing weather-dependent loads, e.g. due to an increasing use of air conditioning during the summer period.

Figure 1 Reference Summer Peak Load Forecasts (2002 vs. 2005 Triennial Review)

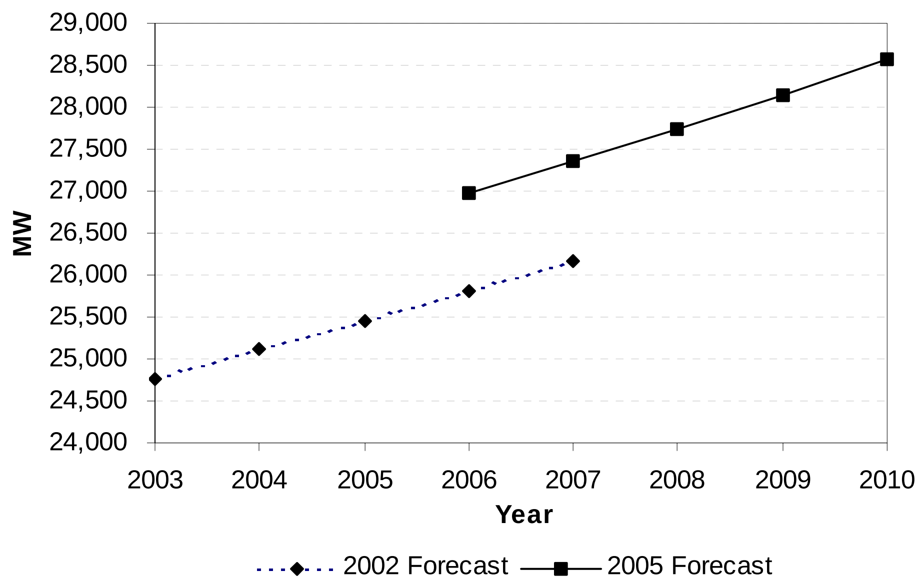

Figure 2 compares the projected installed capacity (summer rating) for the 2002 and 2005 Triennial Reviews.

Figure 2 Projected Summer Capacity[3] (2002 vs. 2005 Triennial Review)

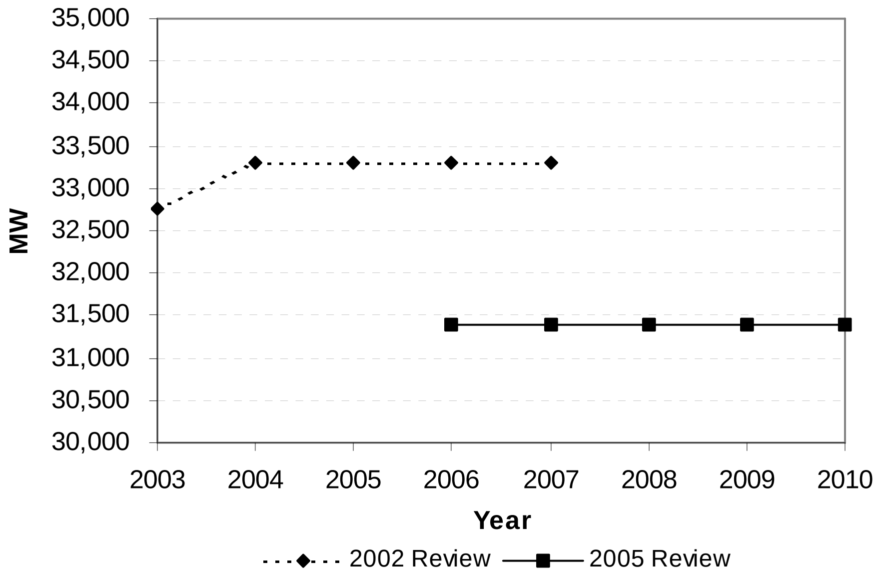

Table 4 to Table 6 summarize the capacity addition, retirement and deactivation assumptions for the 2002 and 2005 Reviews. Note that capacity deactivation for the 2002 Review was modeled only in the Sensitivity Case.

Table 4 Assumed New Capacity Additions (Summer Ratings)

2002 Review	2005 Review	
Capacity Addition Assumed (MW)	Capacity That Has Come Online after 2002 Review (MW)	Capacity Addition Assumed for 2005 Review (MW)
5,984	5,235	8.4

Table 5 Assumed Capacity Retirement (Summer Ratings)

2002 Review	2005 Review	
Capacity Retirement Assumed (MW)	Capacity Retired after 2002 Review (MW)	Capacity Retirement Assumed for 2005 Review (MW)
354	931	0

Table 6 Assumed Capacity Deactivation (Summer Ratings)

2002 Review	2005 Review	
Capacity Deactivation Assumed (MW)	Capacity Deactivated as of May 2005 (MW)	Capacity Deactivation Assumed for 2005 Review (MW)
231	219	219

[3] Capacity is the sum of New England Internal Installed Capacity (reflecting projected additions, retirements, deactivations and rerating) + Firm Purchases from neighboring control areas.

The 2002 review projected a total 5,984 MW of capacity additions by year 2003. As of May 2005, all the units had come online, with the exception of Meriden Power (536 MW), which has stopped construction. As of November of 2005, a total of 14 new generation projects (about 1,900 MW) have been proposed and approved for interconnection in New England. For this review, only 8.4 MW was assumed to be installed during the study period. Since the last review, New England has approved a total of 931 MW of capacity for retirement. As of May 2005, 219 MW of capacity is under deactivation status, and that capacity is assumed to remain deactivated under this review.

In both 2002 Review and this review, Demand-Side Management (DSM) resources were modeled, as an adjustment to the load forecast. Table 7 summarizes the MW amount of such DSM resources assumed in these two reviews.

Table 7 Demand-Side Management Comparison (MW)

Year	2003	2004	2005	2006	2007	2008	2009	2010
2002 Review	1,553	1,586	1,645	1,700	1,740	-	-	-
2005 Review	-	-	-	1,603	1,656	1,690	1,696	1,656

In the 2002 Review, load response program resources were not modeled. In this review, ISO-NE included the load relief obtainable from the implementation of load response programs. The amount of load relief assumed obtainable is:

Dispatchable and Interruptible Loads (Including SWCT RFP)	295 MW (Year 2006)
	301 MW (Year 2007)
	301 MW (Year 2008)
	45 MW (Year 2009)
	45 MW (Year 2010)

ISO-NE also takes into consideration the load relief from implementing system wide voltage reduction in its resource adequacy assessment. Based on field test results, it is assumed that the implementation of 5% voltage reduction would reduce the hourly load by 1.5 %. In the 2002 review, the reduction of hourly load resulting from the 5% voltage reduction test results was 1.33%.

4.0 Resource Adequacy Criterion

4.1. Statement of New England Resource Adequacy Criterion

The New England Resource Adequacy Criterion[4] complies with the NPCC criterion and reads:

"Resources will be planned and installed in such a manner that, after due allowance for the factors enumerated below, the probability of disconnecting noninterruptible customers due to resource deficiency, on the average, will be no more than once in ten years. Compliance with this criteria shall be evaluated probabilistically, such that the loss of load expectation [LOLE] of disconnecting noninterruptible customers due to resource deficiencies shall be, on average, no more than 0.1 day per year.

a. *The possibility that load forecasts may be exceeded as a result of weather variations.*

b. *Immature and mature equivalent forced outage rates appropriate for generating units of various sizes and types, recognizing partial and full outages.*

c. *Due allowance for scheduled outages and deratings.*

d. *Seasonal adjustment of resource capability.*

e. *Proper maintenance requirements.*

f. *Available operating procedures.*

g. *The reliability benefits of interconnections with systems that are not Governance Participants.*

h. *Such other factors as may from time-to-time be appropriate."*

4.2. Application of New England Resource Adequacy Criterion

The New England Resource Adequacy Criterion is used to determine the amount of resources needed to reliably satisfy system demand. In calculating the amount of resources needed, New England also takes into account the tie benefits that are assumed available from neighboring systems. The tie benefits are modeled as available capacity on a seasonal basis. The Hydro-Québec, New York and New Brunswick interconnections have been modeled.

To properly capture the intended operation of the system, the emergency operating procedures that are implemented during periods of capacity deficiencies are also modeled in the form of the amount of load relief that is obtainable. It is assumed that the system operators will always maintain at least some minimum level of operating reserve to ensure control over transmission loadings and maintain a minimum reliability level.

[4] http://www.iso-ne.com/rules_proceds/isone_plan/PP3_R2.doc

The amount of additional generation and load relief that may be obtained during a capacity deficiency is shown in Table 8. This table provides the different actions and their priority when implementing ISO New England Operating Procedure No 4 (OP 4) – *Action During A Capacity Deficiency*[5]. In actual practice, these actions may be implemented in a different order to reflect the current situation and the magnitude of the expected deficiency experienced at the time. Actions 1 to 13 were modeled in this review. OP 4 Actions 14 to 16 were not modeled as load relief in this reliability assessment and are therefore listed as contingency resources. The amount of capacity assistance obtainable through OP 4 Action 11 is modeled as tie reliability benefits and the assumed benefits are shown in Appendix A.1.3.

Load relief from OP 4 actions is assumed to be constant through the study period except for the load relief obtainable through voltage reduction, which is assumed to be 1.5 percent of the system-wide peak demand.

4.3. Statement of Required Resources

New England does not have a required reserve margin criterion. Required resources are planned based on meeting the NPCC LOLE reliability criterion of no more than one day in ten years disconnection of non-interruptible customers.

Interconnection benefits from the neighboring control areas of New York, Hydro Quebec, and Maritimes are modeled in this review. The value of such interconnections in terms of MW is tabulated in Appendix A1.3.1.

4.4. Comparison of New England and NPCC Resource Reliability Criterion

New England's Resource Adequacy Criterion as defined in Section 4.1 complies with the Resource Adequacy Criterion established by the NPCC.

4.5. Resource Adequacy Studies Conducted Since the 2002 Triennial Review

As part of the annual planning process, ISO-NE conducted various sub-area resource adequacy studies each year. The study results since the last Triennial Review were detailed in the Regional Transmission Expansion Plans (RTEP03 and RTEP04), and RSP05[6].

RSP05 identifies system improvements needed over the next 10 years and provides information on what infrastructure improvements are needed and when and where they are needed to meet the system's peak demands in conformance with planning criteria. Plans for the region's future electric infrastructure must account for the uncertainty of assumptions over the next 10 years in terms of load growth, fuel prices, new technology, market changes, environmental requirements,

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

[6] http://www.iso-ne.com/trans/rsp/index.htmlFor copies of this draft RSP05, please contact consumer service of ISO New England at 413-540-4220, or custserv@iso-ne.com.

Table 8 Appendix A – Estimates of Additional Generation and Load Relief From System Wide Implementation of Actions in ISO New England Operating Procedure No. 4 - Action During a Capacity Deficiency Based on a 26,355 MW System Load

Action #	Description	MW
1	Implement Power Caution and advise generators to prepare to provide emergency energy	0
2	Order on generation <5 MW, opting for OP 4 triggered dispatch per OP 14 Request "Settlement Only" units under 5 MW to come on line via Special Notices	47
3	Interrupt Real-Time Demand Response, 2 hour or less notification - Block A Interrupt Real-Time Profiled Response Resources	11.9 18.3
4	Interrupt Real-Time Demand Response, 2 hour or less notification - Block B	0
5	Interrupt Real-Time Demand Response, 2 hour or less notification - Block C	0
6	Begin to allow depletion of 30-minute reserve	About 600 MW, depending on NE's 2nd largest contingency
7	Interrupt Real-Time Demand Response, 2 hour or less notification - Block D	0
8	Interrupt Real-Time Demand Response, 2 hour or less notification - Block E	0
9	Voluntary Load Curtailment of New England Participants' Facilities. Implement Power Watch. Interrupt Real-Time Demand Response - 30 minutes or less notification, not requiring voltage reduction to be implemented Implement Power Watch	40 57.7 0
10	Transmission Customer Generation Contractually Available to Market Participants During a Capacity Deficiency	5
11	Schedule Market Participant-submitted EETs Arrange to purchase Control Area-to-Control Area emergency	Variable (could be between 0 and 1,000 MW)
12	Implementation of 5%Voltage Reduction (VR) requiring more than 10 minutes. Interrupt Real-Time Demand Response – 30 minute or less notification, requiring voltage reduction to be implemented *In later actions of OP4 the New England ten-minute reserve may be allowed to diminish to maintain an absolute minimum required level*.	5 189 *About 1,000 MW depending on system conditions and circumstances and on NE's largest contingency*.
13	Implementation of 5% VR requiring 10 minutes or less.	395
14a 14b	Transmission Customer Generation Not Contractually Available to Market Participants During a Capacity Deficiency Voluntary Load Curtailment by Large Industrial and Commercial Customers Total Action 14	5 200[7] 200-205
15	Radio and TV Appeals for Voluntary Load Curtailment. Implement Power Warning	200
16	Request State Governors to Reinforce Appeals for Voluntary Load Curtailment and Declaration of Power Warning	100
Grand Total		3,075.1 – 4,083.1

[7] The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.

and other relevant events. As with previous planning reports, formerly called Regional Transmission Expansion Plans (RTEPs), RSP05 provides technical information and data on various scenarios and identifies the requirements for maintaining, improving, and ensuring the reliability of the system in the short term. The plan also assists in linking physical system needs to wholesale market mechanisms aimed at attracting market solutions (generation, demand response, etc.) to mitigate these needs. RSP05 thus is a broader plan of the region's electric system needs than the previous RTEP reports.

RSP05 resource adequacy studies are consistent with previous RTEP findings that indicated the need for significant new generation or demand-side resources in New England in the 2008 to 2010 timeframe. Key findings of RSP05 are as follows:

- RSP05 identifies 272 transmission projects required for the reliability of the New England system. Previous RTEP reports emphasized the major 345 kV projects. RSP05 reinforces the need for the major 345 kV projects and, in addition, places greater emphasis on the need for transmission projects throughout the system and particularly within load pockets.[8]
- Under high-demand conditions, New England more likely will be forced to operate under emergency conditions as soon as 2006 due to resource limitations in the Connecticut (CT), Southwest Connecticut (SWCT), and Norwalk/Stamford Subareas (NOR).[9]
- From a systemwide perspective, installed capacity projections show that additional resources are needed to meet systemwide demand as early as 2008 but no later than 2010.
- Analysis of operating reserves shows the immediate need for approximately 1,100 MW of incremental quick-start resources or units with competitive energy prices in BOSTON and Greater Connecticut, especially in Greater Southwest Connecticut.[10] Adding 530 MW (of the 1,070 MW) in Greater Connecticut will meet this area's capacity needs and also serve to meet systemwide needs.
- The region must convert 400 MW of gas-fired generation to dual-fuel capability (i.e., having the flexibility and storage capacity to use oil as well as gas) by winter 2006/2007, and increase that capability by 250 MW per year through winter 2008/2009 and 500 MW more in winter 2009/2010.

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[8] Load pockets are areas of the system where the transmission capability is not adequate to import capacity from other parts of the system, and load must rely on local generation.

[9] To conduct resource planning reliability studies within New England, the region is modeled as 13 sub-areas and three neighboring control areas. In addition to SWCT, NOR, and CT, these sub-areas include northeastern Maine (BHE); western and central Maine/Saco Valley, New Hampshire (ME); southeastern Maine (SME); northern, eastern, and central New Hampshire/eastern Vermont and southwestern Maine (NH); Vermont/southwestern New Hampshire (VT); Greater Boston, including the North Shore (BOSTON); central Massachusetts/northeastern Massachusetts (CMA/NEMA); western Massachusetts (WMA); southeastern Massachusetts/Newport, Rhode Island (SEMA); and Rhode Island bordering Massachusetts (RI). The three neighboring control areas are New York, Hydro-Quebec, and the Maritimes.

[10] Quick-start capacity typically is comprised of pumped storage and conventional hydro units, combustion turbines, many load-response (i.e., load-reduction) program resources, and internal combustion units that can start up and be at full load in less than 30 minutes. These units provide greater operating flexibility in daily operations and in emergency situations than base-load generators, which are available at all times to serve load, or generators that are available to serve intermediate load levels. In daily operations, quick-start resources can help replenish the capacity lost due to a sudden and unexpected loss of a generating unit or transmission facility. Under severe peak-load conditions, quick-start units can help avoid the need to implement involuntary load shedding by providing either energy or operating reserves.

5.0 Resource Adequacy Assessment

5.1. Based On Reference Load Forecast[11]

5.1.1. Base Case

The Base Case is based on all the major assumptions listed in Table 1, and also assumes that all planned transmission upgrade projects will be completed as expected. Table 9 lists these transmission upgrade projects and the target completion dates.

Table 9 Transmission Upgrade Projects and Target Completion Dates

Name of Transmission Upgrade Project	Approximate Resulting Transfer Capability Increase (MW)	Target Completion Date
Southwest Connecticut Reliability Project – Phase I / Phase II	Southwest CT Import: 275/1,100 Norwalk / Stamford Import: 200/550	year 2007/2010
NSTAR 345 kV Transmission Reliability Project Phase I /Phase II	Boston Import: 900/1,100	year 2006/2007
Northeast Reliability Interconnection Project	New Brunswick to New England: 300 Orrington South: 100 Surowiec South: 150 Maine to New Hampshire: 100	year 2007

5.1.2. Sensitivity Case

As a Sensitivity Case, all the planned transmission upgrade projects listed in Table 9 are assumed to be delayed beyond the study period. All other assumptions are the same as the Base Case. Table 10 shows the Base Case and Sensitivity Case LOLE results based on the reference load forecast.

Table 10 LOLE Results Based on Reference Load Forecast

Year	Summer Reference Peak Load (MW)	Installed Capacity (MW)	LOLE (days per year)	
			Base Case	Sensitivity Case
2006	26,970	31,393	0.0196	0.0281
2007	27,350	31,393	0.0276	0.0406
2008	27,750	31,393	0.0447	0.0598
2009	28,145	31,393	0.0976	0.1401
2010	28,565	31,393	0.1440	0.1996

5.2. Based On High Load Forecast

Recognizing the impact of load forecast uncertainty on LOLE and subsequently capacity resource requirements, ISO-NE also analyzed the system resource adequacy under a higher than expected load forecast, which would mainly be due to higher economic growth.

Table 11 shows the Base Case and the Sensitivity Case results under the high load forecast.

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[11] The reference peak load forecast is characterized as having a "50/50" percent probability of occurring.

Table 11 LOLE Results Based on High Load Forecast

Year	Summer High Peak Load (MW)	Installed Capacity (MW)	LOLE (days per year)	
			Base Case	Sensitivity Case
2006	27,210	31,393	0.0256	0.0347
2007	27,875	31,393	0.0499	0.0684
2008	28,570	31,393	0.0977	0.1251
2009	29,220	31,393	0.2379	0.3181
2010	29,920	31,393	0.3970	0.5171

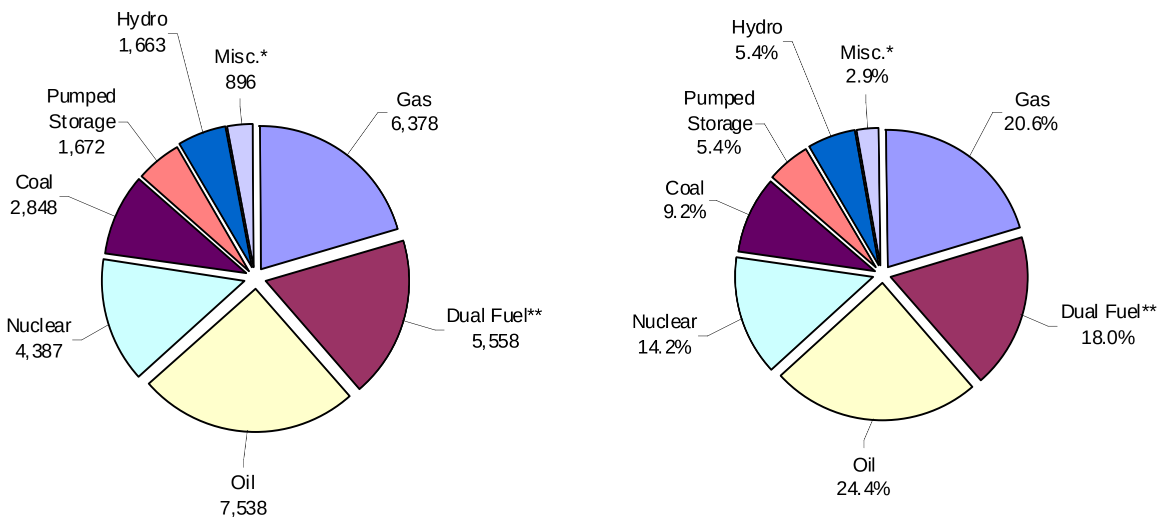
5.3. Mechanisms to Mitigate Potential Reliability Impacts of Uncertainty

The New England bulk power system has been deregulated since 1999. This means that the installation of generating resources is market driven. Incentives to promote new generation entries into the market will depend on market signals. ISO New England provides market signals regarding resource needs through the annual Regional System Plan (RSP). The 2005 RSP was approved by the ISO New England Board of Directors on October 21, 2005. In that plan, ISO New England identified the year, the location and the amount of resources and transmission projects needed to meet system reliability. To provide additional incentives to resources to site at locations where they are needed the most, in 2004, ISO-NE has filed with the Federal Energy Regulatory Commission (FERC) a proposal to implement a Locational Installed Capacity (LICAP) market. The LICAP market is aimed to provide incentives to resources to be installed in the New England system where they are needed the most. In August 2005, FERC issued an order delaying the implementation of the LICAP market no earlier than October 1, 2006.

In the event that market signals do not promote adequate generation or demand response resource installations, the ISO New England has the ability to issue special Request for Proposals (RFP) for generating or demand response resources to meet system reliability. At present, there is an emergency RFP in place for southwest Connecticut where over 250 MW of resources have been purchased and installed through this RFP for use during the summer months to support system resource needs in New England. This program is targeted to end in 2008, when transmission upgrades to southwest Connecticut is expected to be in-service. To address fuel supply concerns this winter of 2005/06, ISO New England has filed with the FERC to implement a Demand Response Winter Supplemental Program covering December 1, 2005 through March 31, 2006. This program is intended to enroll up to 450 MW of demand response programs that will be used to mitigate capacity needs during this coming winter period. To preserve existing generating resource from deactivation or retirement, the current procedures in New England require that generating units obtain approval from ISO New England before they are allowed to retire or deactivate. ISO New England can enter into financial Reliability Must Run agreements with generating resources that are needed for system reliability.

6.0 Planned Resource Capacity Mix

Figure 3 New England's Resource Capacity Mix By Fuel Type in MW and Percentage



Note: Figure 3 assumed New England installed capacity by primary fuel type, summer 2005 (MW and percent). Totals include settlement-only units. Units in the "Miscellaneous" category (*) include those fueled by biomass, refuse, and wind. Dual-fuel capacity (**) is based on units with gas as the primary fuel; 11.5 percent of the units have oil as the primary fuel and gas as the alternative fuel. Total percentage does not add up to 100 due to rounding.

As shown in Figure 3, *New England's Resource Capacity Mix by Fuel Type,* approximately 39 percent of New England's generation fleet has the capability to burn natural gas as the primary fuel source. Recently, questions have arisen regarding whether New England has become over-reliant on natural gas as a primary fuel source for electric power generation. It is true that the supply-side resource mix has changed dramatically in recent years, from a very diverse fuel mix in the 1990's to a scenario now of possible over-reliance on natural gas. Clean-burning natural gas as a major fuel source for electricity generation may not be objectionable, but without the proper contracting levels (supply and delivery) and without the capability to switch to liquid fuels in order to ride out temporary disruptions within the natural gas fuel supply chain, New England may be positioning itself for continued winter reliability concerns.

6.1. Reliability Impacts Resulting from the Proposed Resources Fuel Supply and Transportation and/or Environmental Restrictions

6.1.1. New England's Generation Fleet is Vulnerable to Natural Gas Interruptions

As experienced in New England during the January 2004 Cold Snap, during periods of extreme winter cold, the demand for natural gas within the core gas market for space heating and other uses occurs coincidently with electric power production. ISO-NE had previously conducted studies of New England's interstate natural gas pipeline system, which showed that there is not enough natural gas pipeline capacity flowing into and throughout the region to satisfy the simultaneous winter demand of both the local gas distribution companies (LDCs) and the burgeoning gas-fired electric generation sector. In New England, the gas LDCs have traditionally funded the majority of pipeline expansion and therefore, hold the majority of the contract rights and entitlements of that pipeline capacity.[12] Since most gas-fired electric power generators do not hold firm gas transportation contracts covering the winter peak-load use period, the electric power sector has a fuel supply reliability risk during periods of extremely cold weather.

6.1.2. A Cold Snap Proved the Point

This problem of coincident peak demand materialized during January 14 – 16, 2004, when both the demand for natural gas and electricity in New England hit an all-time seasonal record peak.[13] ISO-NE now refers to this period as the "January 2004 Cold Snap." During this period, a record-setting amount of electric power generation, primarily gas-fired generation, became unavailable due to a number of reasons, and ISO-NE was required to invoke Emergency Operating Procedures (EOPs) to maintain the reliability of the regional power grid. Negative spark spreads, exercising of contractual rights, gas/electric market arbitrage, tight/illiquid spot market gas trading, and overall weather-induced equipment failures were all identified as reasons for decreased gas-fired unit availability. Fortunately, both the natural gas and electric power sectors managed to serve the record peak demand without loss of service to customers. However, the January 2004 Cold Snap was clearly a 'wake-up-call' to the electric power sector with respect to ensuring system reliability during periods of extreme winter peak demand.

6.2. Mechanisms to Mitigate any Potential Reliability Impacts of Resource Fuel Supply and Transportation Issues and/or Environmental Restrictions

Following the January 2004 Cold Snap, ISO-NE conducted a number of investigations. Early investigations conducted by ISO-NE's Market Monitoring Unit (MMU) culminated in both *an Interim and a Final Report*[14] *on Electricity Supply Conditions in New England During the January 14-16, 2004 "Cold Snap"*.[15] The MMU Reports provided over 23 recommendations, corresponding to over 40 action items that the ISO-NE should investigate and possibly implement in order to better prepare for and operate through a future Cold Snap occurrence. Subsequent ISO-NE activities focused on implementing the remedial solutions emanating from the recommendations in those *Interim* and *Final* Cold Snap reports.

6.2.1. A New Cold Weather Event Operating Procedure

After the January 2004 Cold Snap, ISO-NE and various stakeholders from both the electric and natural gas industries worked to produce a short-term remedial market solution. The improvement was the development of a new "Cold Weather Event" Operating Procedure,[16]

[12] Gas-fired power generators in New England hold, in aggregate, approximately 0.8 billion cubic feet per day (Bcf/d) of firm transportation rights to natural gas trading hubs located outside New England. This can supply approximately 4,300 MW of electrical generating capacity.

[13] New England experienced its all-time winter peak demand of 22,818 MW on January 15, 2004.

[14] Interim Report published May 10, 2004. Final Report published October 12, 2004.

[15] These reports, along with others, can be found on ISO-NE's web site at: http://www.iso-ne.com/pubs/spcl_rpts/2005/cld_snp_rpt/index.html

[16] Originally developed in the fall of 2004 as NEPOOL Operating Procedure No. 20 – Cold Weather Event Operations. Subsequently changed to ISO Operating Procedure No. 20 upon the transformation of ISO-NE to a Regional Transmission Organization (RTO) on February 1, 2005. Has since been moved and renamed Appendix H of Market Rule No. 1, at the direction of the FERC.

designed to forecast, provide notification, and temporarily modify wholesale electric market trading deadlines. Upon being triggered, the day-ahead electric trading deadline would be rolled back several hours in order to provide gas-fired electric power generators with the capability to minimize risk through early procurement of commodity and nomination of transportation. The new Operating Procedure also encourages fuel switching from natural gas to liquid fuel oil, subject to permitting and operational capability. Initial stages of the new Operating Procedure were triggered during the winter of 2004/2005. However, the last stage, declaration of a "Cold Weather Event," which would have realigned the wholesale electric market timeline, never materialized [17]. The new Operating Procedure will again be in effect for the winter of 2005/2006 and has with it a "*sunset clause*" scheduling for automatic termination on April 15, 2006.

6.2.2. Identifying Gas-fired Generation's Contractual Arrangements

After the January 2004 Cold Snap, ISO-NE undertook an investigation to identify all the contractual transportation entitlements held by in-region gas-fired power generators. In theory, gas-fired power generators with firm gas pipeline transportation contracts linked to outside the region should be able to *"spin gas into electricity"* during future Cold Snaps, barring arbitrage. However, ISO-NE's assessment revealed that only about 4,300 MW out of 11,936 MW of gas and dual fuel units have firm gas transportation (pipeline) contracts linking them to natural gas trading hubs located outside the region. In fall of 2004, ISO-NE developed a database of gas transportation contracts held by gas-fired generators. ISO-NE plans to perform an update to this contract assessment during the fall of 2005, in order to re-verify which units' contractual arrangements put them in a 'positive' position to deliver energy during extreme winter weather.

6.2.3. Increased Communications with the Regional Natural Gas Industry

After the Cold Snap, ISO-NE and stakeholders from the regional natural gas industry created the Electric/Gas Operations Committee (EGOC). The objective in the formation of the EGOC was the shared goal of promoting greater regional reliability of the electric and natural gas systems through improved education, understanding, communications and coordination. It was envisioned that the EGOC would be responsible for cross-training of electric and gas system operators, establishing emergency communications protocols and procedures, assessing and addressing system restoration issues, assessing coordination of electric and gas system maintenance requirements, and addressing other common issues.

The EGOC held several meetings during 2004 and 2005 to address their charter. The most significant accomplishment has been the increased communications between ISO-NE and the regional gas sector, which during the winter of 2004/2005 culminated in routine (weekly) communications between both parties. Communication dealt with understanding the public domain information posted on each other's websites.[18] Emergency communication manuals and operational contact information were disseminated to both sectors, and employee training of

[17] Post-operational analysis of Winter 2004/2005 can be found at: http://www.iso-ne.com/pubs/spcl_rpts/2005/cld_snp_rpt/Cold%20Snap%20Report%20Final_CW.pdf

[18] Natural gas pipelines support electronic bulletin boards (EBBs) capable of posting information on nomination/confirmation of gas shipments.

opposite systems was carried out. This communications protocol[19] continues today and is expected to again be in place during the winter of 2005/2006.

6.2.4. Increasing Dual-Fuel Capability

A key recommendation identified within the Cold Snap studies was to encourage maximization and sustainability of existing dual-fuel capability as well as expand dual-fuel capability to gas-only units. The study[20] found that many gas-fired units had air permits to burn limited amounts of liquid fuel oil during emergency periods. However, in some cases, these air permits were ambiguous about when these units could actually burn oil. Furthermore, many of these units with air permits to burn liquids had not installed the necessary hardware (burner systems, software control, etc) or support infrastructure (on-site storage) to facilitate dual-fuel operation. ISO-NE has worked and continues to work with regional air regulators to review existing power plant Operating Permits (OP) with respect to clarifying existing language and incorporating exemption clauses that will allow limited or extended oil-burning operation only during periods when the electric power system is in an abnormal state (invocation of Emergency and/or Cold Weather Operating Procedures) or when the natural gas supply and/or delivery system has been constrained or curtailed due to force majeure type events. ISO-NE is currently working to assess the true capability and sustainability of dual-fuel operation across the generation fleet, with emphasis on determining the exact amount and location of dual-fuel capacity required to sustain reliable winter operations.

6.2.5. "Peaking Gas" Study

As part of ISO-NE's remedial investigations, an analysis of "peaking gas" services was recommended as a possible solution to providing quick-start gas-fired electric power generators with their necessary fuel requirements. ISO-NE assessed whether or not a new fuel reliability service targeted primarily at electric peaking capacity could be developed within the natural gas sector. With such a service, gas-fueled units could be called online with very short-notice (usually within a 10- or 30-minute timeframe) to respond to real-time contingencies to replace lost energy and/or replenish operating reserves. In the fall of 2004, ISO-NE hired a consultant to undertake this assessment.

It is important to note that within the natural gas industry, the term *"peaking service"* is generally associated with a full day of service provided during peak load periods. The service envisioned can be more accurately described as *"no-notice"* service, and comes with its own unique set of operating constraints. The assessment concentrated on the use of no-notice services, which are typically utilized for periods shorter than one day and do not adhere to the standard gas nomination and scheduling timelines. The assessment identified the potential participants, the character of potential service offerings and the resulting regulatory and pricing implications involved with these new services. Please note that the assessment is based upon New England's existing (circa 2004) market rules and regulatory structure for both the gas and electric industries. The major findings of this assessment are highlighted below:

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[19] The protocol ensures that ISO-NE abides by the ISO Information Policy and the gas sector compiles with antitrust provisions.

[20] The study entitled *Dual-Fuel Generating Capacity and Environmental Constraints Analysis – Interim Report*, dated April 1, 2005 can be found on ISO-NE web-site under the directory: http://www.iso-ne.com/pubs/spcl_rpts/2005/cld_snp_rpt/1_dual_fuel_interim_report.pdf

- The physical and scheduling complexity of providing no-notice service currently limits the sellers in the marketplace to the gas LDCs. In addition, sale of no-notice services by LDCs during peak load conditions may be seen as problematic by state regulators. It was also determined that regional gas marketers could not currently provide no-notice services on a firm basis since they traditionally do not control the required pipeline capacity or gas peaking assets, such as LNG or market area storage.

- The presumed high cost of a no-notice service would limit buyers to single-fuel, gas-only intermediate or peaking units, because dual-fuel units are presumed to have the capability to switch over to liquids. Under the current no-notice service structures, these types of units would also need to be physically located behind the LDC meters (citygate).

- Currently, New England's interstate gas pipelines will not support incremental no-notice type services. To significantly increase the number of generating units that could utilize such a service, additional market signals must be present to entice pipelines (or LDCs) to enter into these newly proposed no-notice service arrangements.

- ISO-NE should weigh the value of expanding dual-fuel capability for peaking requirements against the cost of incremental no-notice services from the natural gas industry. This is especially true for larger generating units (250 - 500 MW) where the substantial fuel requirement would virtually eliminate no-notice service availability.

6.2.6. Studies of the Future Outlook for Gas Supplies and Regional Infrastructure

Additional studies were conducted to examine the outlook for natural gas supplies and infrastructure improvements.[21] Key findings from these studies are as follows:

- New England's historical sources of natural gas supply are projected to decline or remain flat. The potential production quantities from gas basins in areas of the Western Canadian Sedimentary Basin (WCSB) and the offshore eastern coast of Canada (Sable Island) are lower than originally anticipated.

- The regional demand for natural gas continues to grow to supply newly planned electric power generators. Based on the ISO-NE's report entitled *New England Natural Gas Supply Assessment*, over 9,000 MW of planned new gas-fired power plants are considered likely to be built in New York, Ontario, and Québec combined. These new facilities will be competing with New England's power generators for traditional gas supplies and transportation.

- Upward price pressure and competition will continue to be a problem during peak winter periods in New England. As a result of the level of high demand, the regional

[21] ISO-NE's report entitled *New England Natural Gas Supply Assessment*, dated April 1, 2005 can be found on ISO-NE's web site at: http://www.iso-ne.com/pubs/spcl_rpts/2005/cld_snp_rpt/1_dual_fuel_interim_report.pdf. ISO-NE's report entitled *Northeast Natural Gas Infrastructure Assessment*, dated April 1, 2005 can be found at: http://www.iso-ne.com/pubs/spcl_rpts/2005/cld_snp_rpt/7_northeast_natural_gas_infrastructure_assessment.pdf

interstate gas pipelines currently will not support incremental "no-notice" type services. This type of gas contracting could help electric generators secure fuel supply during peak-demand periods or during electrical reserve pick-ups.

- The current market structures for electricity and gas put the gas LDC sector at a competitive advantage over gas-fired electric power generators for purchasing natural gas products and services. This is primarily due to the LDC's ability to "pass-through" the costs to the rate base for recovery, versus the competitive market for wholesale electric energy.

- New LNG import facilities will most likely be required to meet New England's incremental gas-supply requirements in the near term. Siting concerns for proposed LNG projects within New England suggest that the LNG facilities proposed in the Canadian Maritimes may be the first new regional LNG import and storage facilities built.

- New LNG projects that materialize along the existing pipeline routes already developed for Sable Island gas deliveries will also bring benefits to New England's electric sector by back feeding the existing gas grid from the north and relieving the volume of west-to-east flows. This back feeding would create a great deal of residual gas pipeline capacity, which should increase the flexibility for the pipelines to offer additional services.

- The global LNG production chain also has risks. Expanded liquefaction facilities are needed, but they are currently being developed in areas of political unrest. More LNG tankers have been ordered, but there are concerns over obtaining enough skilled maritime crews to operate this new fledgling fleet. There is also seasonal (winter period) global competition for LNG supplies from the growing demand in other areas of the world, all of which are located within the northern hemisphere (i.e., Europe & Asia).

The findings of these studies raise a major concern regarding the future availability of natural gas for electricity generation in New England, given the current uncertainties associated with the future northeast United States and eastern Canadian gas supply, delivery, and demand situation.

6.2.7. Additional Studies within the ISO-NE Regional System Plan

As part of its RTO filing, ISO-NE is charged with producing an annual planning report, currently identified as the 2005 Regional System Plan (RSP05).[22] Within this year's planning assessment, a probabilistic, multi-area reliability simulation program was used to conduct studies to identify the minimum amount of gas-only capacity that must be operable in New England to meet a range of risk levels under expected load and capacity assumptions while accounting for transmission interface limits. The result of these simulations identifies the estimated amount of gas-only capacity that must be available during a natural gas supply shortage or delivery constraint. The

[22] http://www.iso-ne.com/trans/rsp/index.html

availability can be achieved by the use of alternate fuels (therefore requiring the gas-only resource to convert to dual-fuel capability) or access to gas through firm transportation contracts. The study covered the winter periods of 2005/2006 through 2009/2010. Please reference the final approved version of ISO-NE's RSP05 document for the detailed findings and conclusions.

6.2.8. A Three ISO/RTO MOU Coordinates Natural Gas Supply Conditions Related to Power Generation

On June 23, 2005, ISO-NE, New York Independent System Operator (NYISO) and PJM Interconnection signed a Memorandum of Understanding (MOU) to coordinate operations and practices and share information and technology during periods of extreme cold weather and/or abnormal natural gas supply or delivery conditions. Natural gas-fired electric generation accounts for a significant portion of the regional generating capacity.

As the regional electricity industry grows more dependent on natural gas as a primary fuel source for generating resources, it has become apparent that the three northeast power grid operators need to closely coordinate operations and planning to ensure that system reliability is maintained whenever abnormal conditions occur, on either the electric or gas systems. The MOU provides the framework for this coordination.

The MOU will allow the northeast power grid operators to implement best practices to refine their Operating Procedures and communications protocols, interact unilaterally with the regional natural gas sector, undertake common-mode training, and coordinate future study activities. The degree of coordination is purely voluntarily. The MOU creates the Northeast ISO/RTO Natural Gas and Electric Interdependency Coordination Committee (NGEICC), which is currently working on finalizing its charter. ISO-NE has volunteered to chair the Committee.

6.3. Available Mechanisms to Mitigate Potential Reliability Impacts of Resource Capacity Fuel Mix and/or Environmental Restrictions

ISO New England is sensitive to issues relating to fuel supply and diversity. Most of the over 10,000 MW of generating resources installed in New England since 1999 are fueled by natural gas and while gas supply is not yet an issue during the New England summer peak demand season, its availability during the winter is of great concern. ISO New England and NEPOOL participants are investigating market mechanisms to promote fuel diversity. Meanwhile, there are last minute stop gap procedures in place to allow ISO New England to implement special emergency RFP to get resources installed for system resource adequacy and reliability. Prior sections of this Review has provided details of such RFP currently in effect. On October 28, 2005, ISO-NE/NEPOOL has filed with FERC a proposed Action Plan[23] designed to ensure the reliability of New England bulk power system operations during the coming winter, in which natural gas and other generating fuels could be in short supply due to hurricane damages in the Gulf of Mexico Region.

[23] http://www.iso-ne.com/regulatory/ferc/filings/2005/oct/er06-___winter_project_filing2_10-28-05.pdf

APPENDIX

A DESCRIPTION OF RESOURCE RELIABILITY MODEL

The ISO-NE developed Reliability Model was used for conducting this analysis. The ISO Reliability Model uses a procedure to calculate power system risks (i.e. Loss of Load Expectations (LOLE), Loss of Energy Expectations (LOEE)), and determine locational generation and transmission requirements for given risk levels. It combines sequential Monte Carlo simulation and dynamic optimizations to compute the total system risk while quantifying the two contributing components -- capacity shortages and transmission constraints. This means that for each risk index calculated, the breakdown of how much of the risk is from generation shortages and how much is from transmission limitations can be determined. For example, if a system's LOLE was calculated to be 0.1 days/year, the ISO Reliability Model also calculates the risk component that is due to generation inadequacies (say 0.08 days/year), and then the remaining 0.02 days/year is from transmission constraints.

For each hour, the program conducts a random draw to determine each generating unit's availability status (up or down state) while simulating the residence time in each state. The total available capacity is then compared with the hourly load in each sub-area in order to determine the capacity margin. Next, a primary Linear Program (LP) is performed to dispatch the capacity from surplus sub-areas to deficient sub-areas to minimize system load shedding, while honoring the transmission interface limits modeled. The flow in the interfaces between sub-areas from such a dispatch is calculated using a DC load flow model. The primary LP identifies whether or not the current hour is a loss of load event, and the causes of it (if it is generation shortage or transmission constraint).

After the primary LP is completed, a secondary LP is performed. If the outcome of the primary LP is a loss of load event, the secondary LP will determine the minimum amount of needed capacity or transmission interface limit increase in order to eliminate the loss of load event in that hour. If the current hour is not a loss of load event, the secondary LP will determine the maximum amount of capacity and transmission excess. In each instance, the secondary LP also identifies the feasible sub-area location for such additions or surplus while accounting for the transmission interface limitations in the system, and records the results as a solution vector.

After recording the solution vector for the current hour, the program proceeds to the next hour and repeats the steps noted above. This continues for each hour of the year with many years of replication. After the simulation is complete as indicated by the convergence of this process, the program computes the annual system total risk index and its risk components (generation and transmission). Based on the solution vectors recorded for each hour in the secondary LP, a sorting or dynamic programming procedure is employed to examine results and determine the optimal system planning solution based on the given risk criterion. This solution provides the total surplus/deficient generation and transmission by area or interface for a chosen risk level.

The ISO-NE Reliability Model has been benchmarked with the GE MARS model that was used for the calculation of the system risk indices for last Triennial Review. For the Base Case of this Review, both models were used to calculate the system LOLE indices. The results are shown in the following table. The slight differences in the LOLE results are due to the convergence characteristics of probabilistic models. When translated to MW value, these differences are marginal – for example, it is only about tens of MW difference at a 0.1 days/year level.

Table 12 Benchmarking Results between ISO-NE Reliability Model and GE MARS

Year	LOLE (days per year) for Base Case and Reference Load	
	ISO-NE Reliability Model	GE MARS
2006	0.0196	0.0180
2007	0.0276	0.0270
2008	0.0447	0.0460
2009	0.0976	0.1020
2010	0.1440	0.1520

A.1.1 Load Model

A.1.1.1 Hourly Loads

For this review, the ISO Reliability Model uses weekly peak load distributions as input, and internally developed the hourly load profile for the risk calculation. A detailed description of weekly peak load distributions for the New England system is documented in the ISO RSP05 report.

A.1.1.2 Load Forecast Uncertainty

The forecast uncertainty associated with weather was imbedded in the weekly peak load distributions.

A.1.1.3 Demand of Entities that are Not Members of NEPOOL

Not modeled.

A.1.1.4 Demand Side Management Programs

Reference section A.1.5.

A.1.2 Resource Unit Representation

A.1.2.1 Unit Ratings

A.1.2.1.1 Definition

Existing capacity data was based on the Seasonal Claimed Capability (SCC) reported in the April 2005 CELT[24] report. Seasonal Claimed Capability (SCC) represents the Summer (SCC-S) and Winter (SCC-W) Claimed Capability of a generating unit. The summer rating period runs from June 1 through September 30, and the winter rating period runs from October 1 through May 31. Claimed capability is the demonstrated maximum dependable load carrying capability, in megawatts, of such unit, excluding capacity required for station service use.

ISO-NE's CELT reports are published on ISO-NE's website: http://www.iso-ne.com/trans/celt/index.html

A.1.2.1.2 Procedure for Verifying Ratings

ISO-NE has the authority to initiate audits of all generating units to verify their Seasonal Claimed Capability. Audits are initiated by ISO-NE ordering the generator output to be increased from its current operating level (if that level is below SCC) to its SCC. The required duration for a claimed capability audit is at least two hours and no more than eight hours, depending on the Capability Period and type of unit. In order to pass a claimed capability audit, a unit must demonstrate it can achieve average output greater than or equal to Claimed Capability. Full details of the audit process can be found in the New England Manual for Installed Capacity, Manual M-20, Attachment D (Claimed Capability Audits): *http://www.iso-ne.com /rules_proceds/isone_mnls /index.html.*

A.1.2.2 Unit Unavailability Factors Represented

A.1.2.2.1 Unit forced outage assumptions were based on five-year (2000 through 2004) average Equivalent Forced Outage Rate Demand (EFORd). Unit availability reflects the projected scheduled maintenance and forced outages. Individual generating unit maintenance assumptions are based on each unit's previous five-year historical average of scheduled maintenance.

A.1.2.2.2 The unit forced outage data was based on the unit's historical data and North American Reliability Council (NERC) average data for the same class of units. For non-nuclear units, it is determined using a combination of NERC's Class Average from January 2000 to February 2003, and the calculated EFORd using NERC Generating Availability Data System (GADS) data from March 2003 to December 2004. Analysis showed that the nuclear units in New England performed better than NERC Class Average EFORd; therefore, the forced outage data for the nuclear units is determined using ISO-NE calculated EFOR data from January 2000 to February 2003, and the calculated EFORd using GADS from March 2003 to December 2004.

A.1.2.2.3 No specific immaturity unavailability factors are considered in this review.

Table 13 New England Average EFORd By Unit Type

Unit Type	EFORd(%)
FOSSIL	6.71
CC	6.03
DIESEL	5.56
JET	7.09
NUCLEAR	1.35
HYDRO	3.80

[24] The *Capacity, Energy, Loads and Transmission Report* (CELT) is a source of assumptions for use in planning and reliability studies, and fulfills in part the reporting requirements of DOE, NERC Reliability Assessment Subcommittee, NPCC, EEI, EFSB(MA) and New England. The CELT forecast assumptions do not constitute a "plan".

A.1.2.2.4 Table 13 shows the average EFORd for each unit type used in the review.

A.1.2.3 Purchases and Sales Representation

The external capacity contracts that New England market participants have with neighboring systems were modeled. The following firm capacity purchases (in MW) were included in the model.

Table 14 Purchases and Sales (MW)[25]

	Year 2006 - 2010
New Brunswick	0
Hydro-Québec	326
New York	127

A.1.2.4 Retirements & Deactivations

In this review, no future retirement is assumed during the study period. 219 MW of capacity that is currently under deactivation status is assumed to remain deactivated.

A.1.3 Representation Of Interconnected Systems

Tie benefits from Hydro-Québec, New York and New Brunswick were modeled during the summer period. Such benefits were modeled as generating units with certain ratings interconnected to New England system. Each year, ISO-NE evaluated the amount of tie benefits assumptions, taking into account the situation of the capacity, load, transmission, and expansion plans of neighboring systems. The seasonal transmission interface transfer capabilities between the neighboring systems and New England have been determined based on established ISO-NE and NPCC reliability criteria to reflect the best operational practices. For this review, a total of 2,000 MW of tie benefits was assumed for the summer period throughout the study period 2006 - 2010. This 2,000 MW amount is higher than the zero to 1,000 MW range of emergency assistance assumed obtainable in Table 8, which details New England's Operating Procedure No. 4 - *Action During a Capacity Deficiency*. Table 8 assumed a lower amount of emergency purchases because it reflects possible short-term capacity purchases over the interconnections that are modeled as a portion of the tie benefits in this review. Table 15 shows the breakdown of the assumed tie benefits from the external control areas.

Table 15 Assumed Tie Benefits From External Control Areas

External Control Area	Assumed Tie Benefits (MW) June - September
Hydro-Québec	1,200
New Brunswick	200
New York	600
Total	2,000

[25] The number in this table is the net of firm purchases and sales. Positive values represent net purchases.

A.1.4 Modeling of Limited Energy Sources

New England's pumped storage and hydro units were considered available to meet daily and monthly peak loads except when they are on planned maintenance or forced outages.

A.1.5 Modeling of Demand Side Management (DSM)

ISO-NE models DSM as a load adjustment to forecasted monthly New England peak loads as shown in the 2005 CELT Report. The DSM values associated with the annual peak loads used in this review are shown in Table 16 below.

Table 16 New England's DSM Load Adjustment to Summer Peak

Year	2006	2007	2008	2009	2010
Total DSM (MW)	1,603	1,656	1,690	1,696	1,656

The total DSM value is made up of the following categories:

Non-OP 4 Interruptible Contracts:
This is the amount of customer load that is under contract with a utility that can be controlled at the time of system peak in response to a signal by a dispatcher and generally achieved within 10 to 30 minutes.

Peak Load Management:
This is the amount of customer load reduced from or shifted off system peak with only a minimum or no change in energy consumption.

Conservation on Peak:
This is the amount of customer load reduction at the time of system peak due to utility programs, which reduce customer load during many hours of the year.

Loss Adjustment:
This is the estimated reduction in transmission and distribution losses due to the implementation of DSM programs.

A.1.6 Modeling of Resources

Modeling of resources is as described in the above sections.

A1.7 Other Assumptions

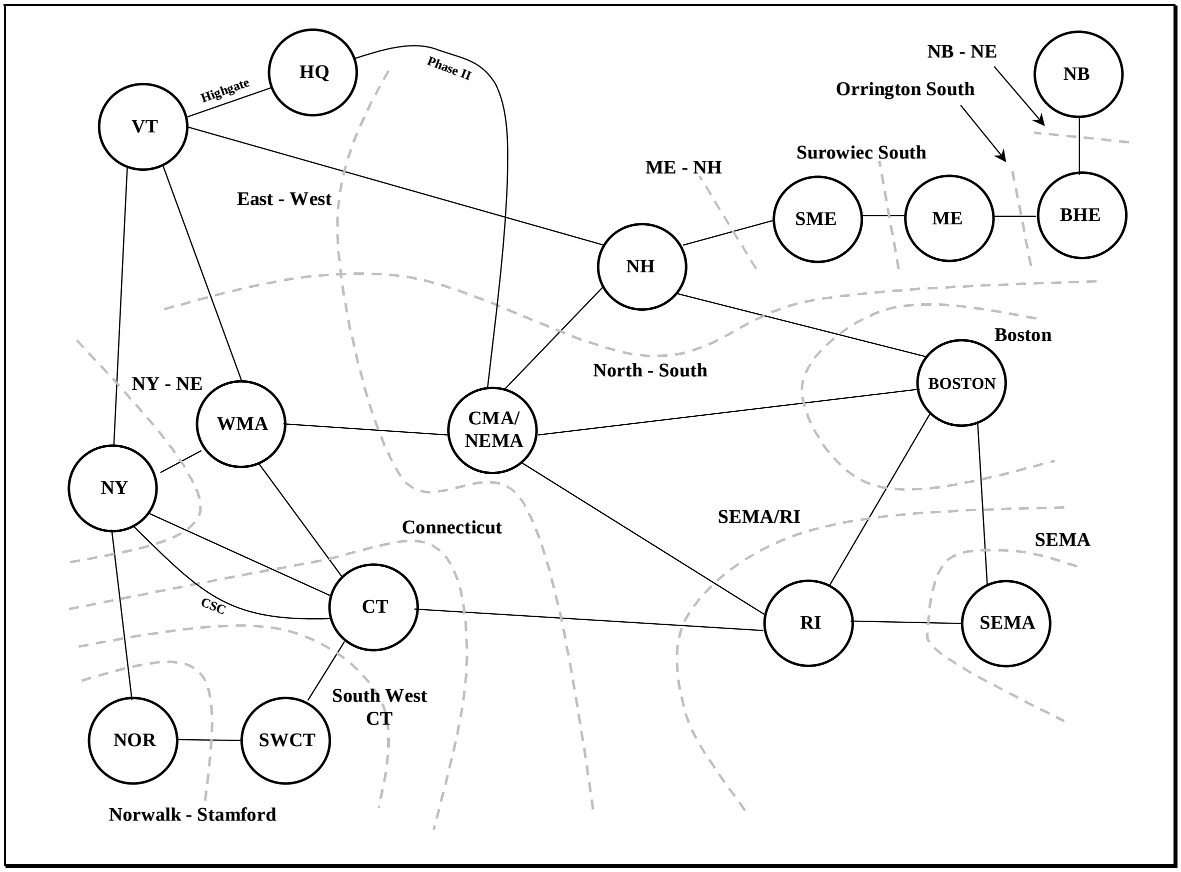
A.1.7.1 New England Internal System Representation

To model expected transmission constraints, the New England system was modeled as 13 interconnected sub-areas, with defined transmission interface limits between them. The transmission interface transfer capabilities between these sub-areas have been determined based on established ISO-NE and NPCC reliability criteria. These criteria are described, respectively, in ISO-NE Planning Procedure No. 3[26], *Reliability Standards for the New England Power Pool*, and NPCC Document A-2[27], *Basic Criteria for Design and Operation of Interconnected Power System.* These criteria require that the interconnected bulk power supply system be designed for a level of reliability such that the loss of a major portion of the system, or unintentional separation of any portion of the system, will not result from reasonably foreseeable contingencies. Therefore, the system must be designed to meet representative contingencies as defined in those criteria. Contingencies are simulated to assess the potential for widespread cascading outages due to overloads, instability, or voltage collapse. New England's bulk power supply system must remain stable during and following the most severe of the contingencies specified in the criteria, with due regard to re-closing facilities and before making any manual system adjustments. Voltages, line loadings, and equipment loadings must be within normal limits for pre-disturbance conditions, and within applicable emergency limits following the contingencies specified in the criteria. Disturbances in New England must not adversely affect other NPCC Control Areas and vice versa. Conversely, the loss of small portions of the system may be tolerated, provided the reliability of the overall interconnected system is not jeopardized.

The interfaces used in the analysis represent potential limiting areas of New England's transmission system, which may become constrained under a variety of system conditions or generation patterns. The most limiting transmission facility and critical contingency which limits the interface transfer, may change depending on unit dispatch, load level, load distribution, and transmission configuration. For modeling purposes, these interface limits are shown as static. Interfaces composed of one or more transmission facilities have been defined to gauge the amount of power which can be transferred between or through various areas before a transmission limitation is reached. Figure 4 shows the New England sub-area representation.

[26] http://www.iso-ne.com/rules_proceds/plan/isone_plan/PP3_R2.doc
[27] http://www.npcc.org/criteria.asp

Figure 4 New England Sub-Area Representation



Sub-areas

BHE	-	Northeast Maine
ME	-	Western & Central Maine / Saco Valley, New Hampshire
SME	-	Southern Maine
NH	-	North, East, & Central New Hampshire / Eastern Vermont & Maine
VT	-	Vermont / Southwest New Hampshire
BOSTON	-	Greater Boston, including North Shore
CMA/NEMA	-	Central Massachusetts / Northeastern Massachusetts
WMA	-	Western Massachusetts
SEMA	-	Southeastern Massachusetts / Newport Rhode Island
RI	-	Rhode Island / bordering Massachusetts
CT	-	North and East Connecticut
SWCT	-	Southwest Connecticut
NOR	-	Norwalk / Stamford, Connecticut

NB, HQ and NY represent the New Brunswick, Hydro-Québec and New York external control areas respectively.

Interface Limits (MW)

Interface or Interface Group	Interface Limit (MW)
New Brunswick to NE	700
	1,000 (Year 2007)
Orrington South	1,050
	1,200 (Year 2007)
Surowiec South	1,150
	1,250 (Year 2007)
Maine – NH	1,400
	1,500 (Year 2007)
North to South	2,700
Boston Import	4,500 (Year 2006)
	4,700 (Year 2007)
SEMA Export	No Limit
SEMA / RI Export	3,000
East to West	2,400
Connecticut Import	2,300
Southwestern CT Import	2,300
	2,575 (Year 2007)
	3,400 (Year 2010)
Norwalk / Stamford Import	1,100
	1,300 (Year 2007)
	1,650 (Year 2010)
New York / New England (Summer)	1,400
New York / New England (Winter)	1,700
HQII Import	1,500
Highgate Import	210

Please note that the power flow on the proposed +/- 330 MW Cross Sound Cable (CSC), a HVDC interconnection between New England and New York, is assumed to be zero during the study period.

A.1.7.2 Environmental Considerations

Environmental considerations, particularly air emissions, are an important aspect in ISO-NE's planning process, since electric generators are a major source of sulfur dioxide, nitrogen oxides, particulates, mercury, and carbon dioxide emissions. Appendix A of ISO-NE's RSP05 discusses a number of topics related to reducing air emissions:

- New England's historical and projected air emissions that provide an emissions "reference trend"
- Developments related to the imposition of a regional cap on CO_2 emissions within the 10-year horizon
- Progress in meeting state Renewable Portfolio Standards that require the development of clean renewable energy sources
- ISO's program for demand response resources

- The status of distributed generation development in New England

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