



NEW ENGLAND 2008 COMPREHENSIVE REVIEW OF Resource Adequacy

ISO New England Inc.

Final Report – Approved by NPCC RCC on November 19, 2008

1.0 EXECUTIVE SUMMARY

ISO New England Inc. (ISO-NE) is the not-for-profit corporation responsible for the reliable operation of New England's bulk power generation and transmission system. It also administers the region's wholesale electricity markets and manages the comprehensive planning of the regional bulk power system. As a part of its planning functions, ISO-NE is the Planning Authority for the New England Area of the Northeast Power Coordinating Council (NPCC). One of the ISO-NE Planning Authority responsibilities is to conduct studies and provide results to demonstrate that the New England Area bulk power system complies with the NPCC *Basic Criteria for Design and Operation of Interconnected Power Systems* (NPCC Document A-2)¹ to satisfy NPCC planning compliance requirements.

This 2008 New England Comprehensive Review of Resource Adequacy, covering 2009 through 2013, was prepared by ISO-NE to satisfy NPCC compliance requirements. This comprehensive review follows the guidelines as specified in the NPCC Document B-8 entitled *Guidelines for Area Review of Resource Adequacy* (Revised: November 29, 2005)². This review supersedes the New England 2005 Triennial Review of Resource Adequacy³, which was approved by the Reliability Coordinating Committee (RCC) on November 29, 2005.

1.1. MAJOR FINDING

The findings of this review are based on the results of a resource adequacy assessment of the New England bulk power supply system using the General Electric Multi Area Reliability Simulation Program (GE MARS) and results of studies conducted for the 2008 New England Regional System Plan (2008 RSP)⁴.

The major findings of this comprehensive review are as follows:

- New England will meet the NPCC resource adequacy criterion of disconnecting firm load customers no more than 0.1 days/year for each year of the study period.
- Fuel supply and transportation will not adversely impact New England's system reliability. ISO-NE routinely conducts operable capacity studies to monitor fuel supply conditions. ISO-NE has existing operating procedures that are specifically designed to mitigate potential adverse impacts on system reliability due to temporary fuel supply constraints or interruptions.
- Environmental regulations, governing both air and water, will not adversely impact New England system reliability.
- ISO-NE expects that new renewable and demand resources will be integrated into New England system operations without adversely impacting system reliability.

¹A copy of the NPCC A-2 can be found at: <http://www.npcc.org/documents/regStandards/Criteria.aspx>

²A copy of the NPCC B-8 can be found at: <http://www.npcc.org/documents/regStandards/Guide.aspx>

³A copy of this review can be found at: <http://www.npcc.org/documents/reviews/Resource.aspx>

⁴You can obtain a copy of the 2008 RSP by contacting ISO New England Customer Service at: 413-535-4000.

- The results of ISO-NE’s first Forward Capacity Auction (FCA) demonstrate that the Forward Capacity Market (FCM⁵) has worked as designed and has attracted significant investment in the development of new resources, both supply and demand side, while maintaining needed existing resources in New England.
- Four (4) major 345 kV transmission projects have been recently completed in four (4) states. Two (2) additional projects that are under construction, reinforce the reliability needs of critical load pockets such as those in Southwest Connecticut and the Boston area. The locational component of the FCM and the reliability review process during the FCA, work to ensure that adequate amounts of resources are procured in the import-constrained areas.

1.2. SUMMARY OF MAJOR ASSUMPTIONS AND RESULTS

Table 1 shows the major assumptions used in this review, and Table 2 summarizes the LOLE results. The detailed assumptions are documented in the Appendix section of this review while the results are documented in sections 5.0 *Resource Adequacy Assessment* and 6.0 *Planned Resource Capacity Mix*.

Table 1 Major Assumptions

Assumptions	Description
Reliability Criterion	NPCC Criterion: no more than once in 10 years of firm load disconnection (LOLE of 0.1 days/ year)
Load Model	Hourly loads with forecast uncertainty
Reliability Model	GE MARS
Resource Availability	EFORd and Planned Maintenance: 5 year average (March 2003 through February 2008)
Tie Benefits from Neighboring Systems	2009: 2,000 MW 2010: 1,860 MW 2011- 2013: 1,800 MW
Emergency Operating Procedures (Load Relief, Voltage Reduction)	Assumed 2.07% of load relief from Voltage Reduction during OP 4 Actions 12 and 13
New Resource Capacity Additions	Include the planned resources under construction as of June, 2008 and those with a supply obligation for 2010/11 FCA
Resource Capacity Retirements/Deactivations	Assumed 0 MW
Internal Transmission Constraints	Modeled. Transmission system representation ⁶ and the interface limits are shown in Appendix A.1.7 of this report.

⁵ For a copy of the market rules, please reference: http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_sect_13-14_eff_9-4-08.pdf

⁶ The subarea representation is consistent with New England’s RSP08.

Table 2 LOLE Results

Year	Expected Resources (MW)	Reference Load Forecast		High Load Forecast	
		50/50 Peak ⁷ (MW)	LOLE (days/year)	50/50 Peak (MW)	LOLE (days/year)
2009	33,280	28,480	0.036	28,585	0.039
2010	34,033	28,955	0.027	29,260	0.037
2011	34,756	29,405	0.032	29,925	0.049
2012	34,756	29,820	0.045	30,565	0.080
2013	34,756	30,190	0.060	31,155	0.123

The resources assumed available for the years 2011 to 2013 for the LOLE calculation are the existing resources that have been qualified to participate in the 2011/12 FCA. The new resources (over 7,000 MW) that have been qualified for the 2011/12 FCA are not included in the LOLE calculation. The actual available resources for the respective period will be those resources that clear in the respective future auctions and assume supply obligations. The potential excess capacity, suggested by the LOLE being less than 0.1 days/year, may or may not be available, depending on the outcomes of these future capacity auctions. However, ISO-NE will procure an adequate amount of resources required to meet the 0.1 days/year criterion.

⁷ The 50/50 peak is the peak load that has 50% chance of being exceeded.

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3.0 INTRODUCTION

As part of its Reliability Assessment Program (RAP), NPCC conducts resource adequacy reviews of its member areas to ascertain whether or not each area will have adequate resources to meet the NPCC Resource Reliability Criterion. The purpose of this report is to document the results of the ISO-NE comprehensive resource adequacy study, covering 2009 to 2013, for NPCC review. The results are documented in accordance with the reporting guidelines as specified in the NPCC Document B-8 entitled *Guidelines for Area Review of Resource Adequacy* (Revised: November 29, 2005)⁸. This study supersedes the New England 2005 Triennial Review of Resource Adequacy⁹, which was approved by the NPCC Reliability Coordinating Committee on November 29, 2005.

Since the 2005 New England Triennial Review of Resource Adequacy, several changes to the New England wholesale power market have occurred. The major change that impacts future regional resource adequacy is the implementation of the Forward Capacity Market.

On June 16, 2006, the Federal Energy Regulatory Commission (FERC) approved a Settlement Agreement¹⁰ to create the FCM in New England. The FCM is a long-term wholesale market designed to promote adequate and economic investment in supply and demand-side resources. The purpose of the FCM is to procure the required amount of installed capacity resources to maintain system reliability, consistent with the region's criteria for resource adequacy. The required installed capacity resources are procured through annual Forward Capacity Auctions that are conducted roughly three years in advance of when the capacity resources must provide service (the "commitment period"). This lead time allows capacity suppliers to develop new capacity resources and enables ISO-NE to plan for these new resources. Capacity resources may include supply from existing and new power plants and/or the decreased use of electricity through demand resources. Both the FCM and FCA are bound by financial-assurance mechanisms and oversight procedures. Capacity transition payments are currently being made to all listed installed capacity during this "transition period", the period of time between now and when the provisions of FCM are first implemented during the year 2010. All listed installed capacity receives their fixed monthly capacity transition payments based on the current Unforced Capacity (UCAP) products. This fixed monthly capacity payment rate is adjusted annually. Existing resources that do not intend to assume supply obligations can choose to submit price related de-list bids in the FCA, or non-price retirement requests, subject to the ISO's review and approval. If the resource is determined by the ISO to be needed for reliability reasons, the resource may then elect to receive cost-of-service compensation which is filed with and approved by FERC.

The first FCA was held in early February 2008 for the commitment period from June 1, 2010 to May 31, 2011. The second FCA for the commitment period from June 1, 2011 to May 31, 2012 is scheduled to occur in December 2008. Section 3.2.2 highlights the results of the first FCA and describes the various capacity resources that have been qualified to participate in the second FCA, and documents the amount of capacity assumed available to meet the expected system needs for the study period.

⁸ A copy of the NPCC B-8 document can be found at: <http://www.npcc.org/documents/regStandards/Guide.aspx>

⁹ A copy of this review can be found at: <http://www.npcc.org/documents/reviews/Resource.aspx>

¹⁰ http://www.iso-ne.com/regulatory/ferc/filings/2006/mar/er03-563-000_030_055_3-7-06_corrected.pdf

The assumptions for resources, load and transmission used for this review are consistent with different aspects of New England's 2008 RSP, Forward Capacity Market, and the 2008 Forecast Report of Capacity, Energy, Loads and Transmission (CELT 2008¹¹).

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

The RCC approved the previous New England Triennial Review of Resource Adequacy in November 2005. The findings of that review showed that New England would meet the NPCC Resource Adequacy Criterion through 2009 and the region would need an additional 170 MW of resources starting in 2010.

3.2. COMPARISON OF CURRENT AND PREVIOUS REVIEWS

3.2.1. LOAD FORECAST

Table 3 tabulates the annual (summer) peak load forecasts used in the 2005 and 2008 reviews. Figure 1 shows these values in graphical form.

The annual (summer) peaks are presented for both the reference load forecast and high load forecast scenarios. The reference load forecast is developed based on a "most likely" long-run economic and demographic forecast from Moody's Economy.com. The high load forecast is developed based on a high growth long-run economic and demographic forecast from Moody's Economy.com.

The peak loads shown in Table 3 have a 50% chance of being exceeded (50/50 peaks) and are expected to occur at a weighted New England-wide, average temperature of 90.4 °F. While Table 3 shows the annual 50/50 peaks of the forecast, the inherent uncertainty of the forecast from weather variations is modeled within the LOLE calculation. The 50/50 peaks are tabulated in Table 3 for ease of reference and to facilitate comparisons.

In the 2005 review, the forecast was explicitly adjusted to reflect the forecasts of reduced energy use resulting from existing and new energy efficiency/conservation programs. However, under the new Forward Capacity Market, these energy efficiency/conservation programs are treated as traditional supply-side resources. As such, these programs are modeled as part of the resource base used to satisfy the resource adequacy criterion and the 2008 forecast, shown in Table 3, has not been adjusted to account for these demand-side resources. To allow for a meaningful comparison of the two peak load forecasts, the energy efficiency/conservation values are removed from the 2008 forecast (167 MW in 2009 and 617 MW in 2010 through 2013) as shown in Table 4.

¹¹ http://www.iso-ne.com/trans/celt/report/2008/2008_celt_report_final.pdf

Table 3 Comparison of Annual Peak Load Forecasts

Period	Annual Peak (MW)			
	Reference Load Forecast		High Load Forecast	
	2008 Review	2005 Review	2008 Review	2005 Review
2009	28,480	28,145	28,585	29,220
2010	28,955	28,565	29,260	29,920
2011	29,405	N/A	29,925	N/A
2012	29,820	N/A	30,565	N/A
2013	30,190	N/A	31,155	N/A

Figure 1 Comparison of Summer Peak Load Forecasts

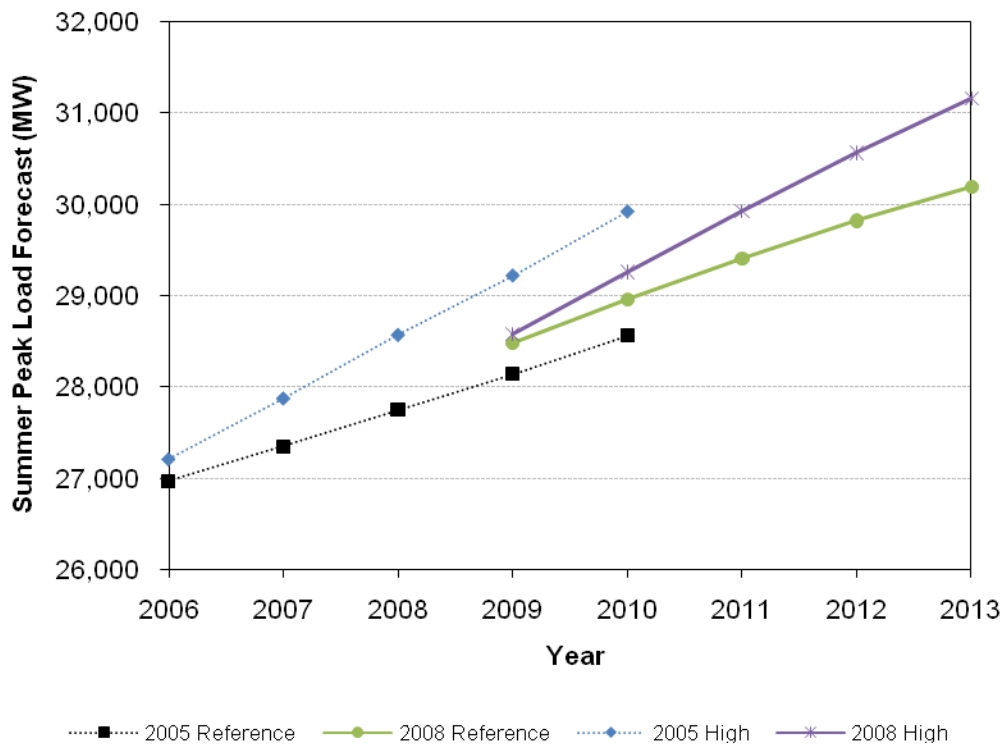


Table 4 Comparison of Annual Peak Load Forecasts (Adjusted for Energy Efficiency/Conservation Programs in 2008 Forecasts)

Period	Annual Peak (MW)			
	Reference Load Forecast		High Load Forecast	
	2008 Review	2005 Review	2008 Review	2005 Review
2009	28,313	28,145	28,418	29,220
2010	28,338	28,565	28,643	29,920
2011	28,788	N/A	29,308	N/A
2012	29,203	N/A	29,948	N/A
2013	29,573	N/A	30,538	N/A

As shown in Table 4, the results of the reference load forecasts for 2009 and 2010 are very close (within 230 MW). The projected Compound Annual Growth Rate (CAGR) of the 2005 Reference Load Forecast was 1.4% from 2006 to 2010. The projected CAGR of the 2008 reference load forecast from 2009 to 2013 is approximately 1.01%, after adjusting for the projected energy efficiency/conservation programs. The lower projected growth in demand of the 2008 forecast reflects a slower regional economic growth, higher projected electricity price assumptions, and higher penetration of energy efficiency and conservation programs, as compared to the 2005 forecast.

3.2.2. RESOURCES

Since the required assessment period for this review, 2009 to 2013, spans different phases of New England's FCA, for each phase, this review has developed different assumptions for the supply and demand resources that may be available to serve electricity demand, to reflect the most likely outcomes of the capacity market.

For 2009, the last year of the transition period of the FCM where all qualified resources receive monthly capacity payment based on a fixed payment rate, this review includes all the existing resources and 530 MW of planned resources that are under construction and expected to be online by June 2009. Since the 2005 Review, about 240 MW of generating resources have been added to the New England system, and the amount of the demand-side resources has also significantly increased from the 2005 value of 300 MW to today's value of 1,800 MW.

The first FCA for 2010 was conducted in February 2008. The auction concluded after eight rounds of bidding when the lower bound of the capacity clearing price collar (\$4.50/kW-month), as defined by the market rules, was reached rather than when supply was equal to the demand in the auction. As a result, a total of 34,033 MW of resources were cleared in the auction with a supply obligation for operation by 2010. This is 1,728 MW above the 32,305 MW of the net Installed Capacity Requirement¹² for 2010/11. It is worth noting that not all of the MWs that cleared in the auction in excess of the Installed Capacity Requirement may be available to the New England system, since in accordance with the market rule, the resources that have cleared in the FCA will have the opportunity to prorate their MWs down to the 32,305 MW requirement level, subject to the ISO's reliability review. The results of the proration process will not be available until late 2008. Therefore, all the resources that have cleared the auction to assume a supply obligation in 2010 are modeled in this review.

The second FCA, for the commitment period of 2011, will be held in December 2008. A total of 34,756¹³ MW of existing resources (31,467 MW of generating resources, 2,384 MW of demand resources, 1,005 MW of external imports and 100 MW of exports), and a total of 7,117 MW of new resources (3,399 MW from generating resources, 1,105 MW from demand resources, and 2,613 MW from external imports) have been qualified to participate in the second FCA. In this review, for the study period of 2011 and beyond, only the existing qualified resources are assumed for the LOLE calculation.

¹² Net Installed Capacity Requirement is the amount of capacity resources that are needed to meet the 0.1 days/year LOLE resource planning reliability criterion.

¹³ This includes the new resources that cleared in the 2010/11 FCA. These new resources are classified as existing resources for the 2011/12 FCA in accordance to the Market Rule 1.

Table 5 and Figure 2 compare the MW values of resources assumed for the 2005 and 2008 reviews.

The NPCC resource adequacy planning criterion allows the use of load and capacity relief from the implementation of emergency operating procedures to meet system capacity needs. Specifically, the tie benefits assumed available from the interconnections and load relief from implementing voltage reductions are used in meeting the 0.1 days/year LOLE but are not reflected in Table 5 and Figure 2. In the 2005 review, tie benefits were assumed to be 2,000 MW and load relief from implementing a 5% voltage reduction was assumed to be a 1.5% reduction from the peak loads. In the 2008 review, the tie benefit assumptions range from 1,800 MW to 2,000 MW and load relief from implementing a 5% voltage reduction is assumed to result in a 2.07% reduction in the peak loads. The 2008 review assumptions are based on recent study results.

Table 5 Comparison of 2008 vs 2005 Resources Assumptions (MW)

Period	Resource Category	2008 Review	2005 Review
2009	Generating Resources	31,402 ¹⁴	30,940
	Demand Resources	1,820	300
	Net Purchase and Sale	58	453
	Subtotal	33,280	31,693
2010	Generating Resources	30,865	30,940
	Demand Resources	2,234 ¹⁵	300
	Net Purchase and Sale	934	453
	Subtotal	34,033¹⁶	31,693
2011 - 2013	Generating Resources	31,467	N/A
	Demand Resources	2,384 ¹⁷	N/A
	Net Purchase and Sale	905	N/A
	Subtotal	34,756	N/A

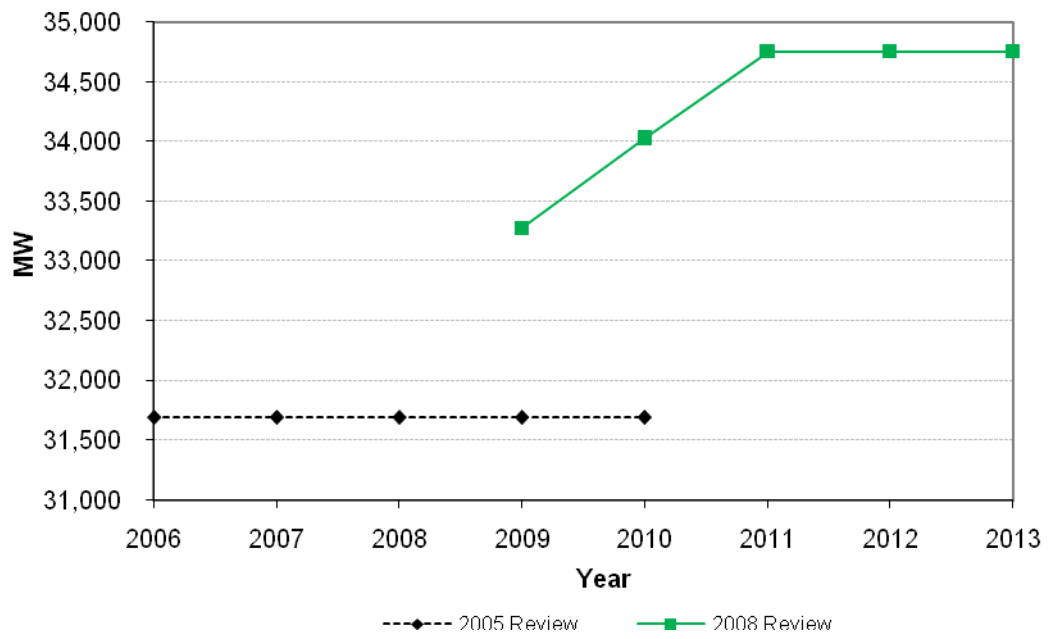
¹⁴ Based on the 2008 CELT report, including planned additions.

¹⁵ This value includes all the cleared real-time emergency generation over the 600 MW cap. It also reflects the 8% transmission and distribution (T&D) loss gross-up, but does not include the reserve margin gross-up.

¹⁶ The 34,033 MW here is slightly different from the 34,077 MW the ISO filed with FERC for resources that cleared in the 2010/11 FCA. The 34,077 MW also includes reserve margin gross-up for demand resources, and the real-time emergency generation value is capped at 600 MW.

¹⁷ This value includes the 8% transmission and distribution loss gross-up, but does not include the reserve margin gross-up.

Figure 2 Comparison of 2008 vs 2005 Resource Assumptions



4.0 RESOURCE ADEQUACY CRITERION

4.1. STATEMENT OF NEW ENGLAND RESOURCE ADEQUACY CRITERION

The New England Resource Adequacy Criterion¹⁸ 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 the neighboring systems. The Hydro-Québec, New York and New Brunswick interconnections have been modeled within this reliability review.

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 assumed 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.

Table 6 documents the actions of ISO New England Operating Procedure No 4 (OP 4) – *Action During A Capacity Deficiency*¹⁹. In actual practice, these actions may be implemented in a

¹⁸ http://www.iso-ne.com/rules_proceeds/isone_plan/index.html, PP03.

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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.

Prior to the FCM implementation on June 1, 2010, demand resources are a part of OP 4 actions. Under the FCM, demand resources will become dispatchable resources and will be implemented prior to declaration of OP 4. The only demand resource that will remain callable only under OP 4 conditions are the emergency generators.

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 systems of New York, Hydro Quebec, and Maritimes are modeled in this review. The value of such interconnections in terms of MWs is tabulated in Table 13 of Appendix A.1.3

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 2005 TRIENNIAL REVIEW

Each year, ISO New England prepares a comprehensive 10-year Regional System Plan to evaluate the system needs and the solutions and process required to ensure the reliable performance of the New England bulk power system. The 2008 plan presents the results and findings of the recent analysis on loads, resources, and transmission of New England's bulk power system through 2017.

¹⁹ OP 4 is activated whenever the system is short of resources to meet expected load plus operating reserve requirement. For details of OP 4, please visit: http://www.iso-ne.com/rules_proceeds/operating/isone/op4/index.html
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Table 6 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 28,048MW System Load²⁰

Action #	Description	MW
1	Implement Power Caution and advise generators to prepare to provide any additional operable capacity available under emergency conditions.	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 ²¹
3	Interrupt Real-Time Demand Response, 2 hour or less notification - Block A Interrupt Real-Time Profiled Response Resources	121.2 16.9
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 2 nd 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	40 498.4 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 <i>In later actions of OP4 the New England ten-minute reserve may be allowed to diminish to maintain an absolute minimum required level.</i> Alert NYISO that sharing of reserves with NPCC may be required	292 949 <i>About 1,000 MW depending on system conditions and circumstances and on NE's largest contingency.</i>
13	Implementation of 5% VR requiring 10 minutes or less.	261
14	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 ²² 200-205
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		4,432 – 5,442

²⁰ MW values are shown in this table for illustration purposes. These will change according to system conditions and market rule modifications.

²¹ Based on Summer Ratings. Assumes 25% of total MWs of Settlement Only units <5 MW will be available and respond.

²² 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.

5.0 RESOURCE ADEQUACY ASSESSMENT

5.1. BASED ON REFERENCE LOAD FORECAST

Table 7 summarizes the LOLE results for the Reference Load forecast scenario and the resource assumptions detailed in Section 3.2. As shown, New England will meet the NPCC resource adequacy criterion of disconnecting firm load customers no more than 0.1 days/year during the study period.

The net Installed Capacity Requirement for 2009 is 31,427 MW and currently there are 33,280 MW of installed capacity to meet this requirement. The net Installed Capacity Requirement for 2010 is 32,305 MW, and a total of 34,033 MW of resources were cleared in the first FCA to assume a supply obligation for operation by 2010. Although the MWs that cleared in the auction in excess of the net Installed Capacity Requirement have the opportunity to prorate down to the 32,305 MW level, subject to the ISO's reliability review, these amounts of procured demand and supply-side capacity should ensure system reliability within New England in 2010.

The net Installed Capacity Requirement needed to meet the 0.1 days/year LOLE for the 2011 Capability Year is 32,528 MW. ISO New England has qualified 34,756 MW of existing resources to participate in the FCA for 2011, which is scheduled for December 2008. Based on the amount of resources qualified to participate in this second FCA, New England will have a more than adequate amount of resources to satisfy the resource adequacy criterion. In addition, a total of 7,119 MW of new resources (3,399 MW from generating resources, 1,105 MW from demand resources, and 2,613 MW from external imports), also have qualified to participate in the second FCA. ISO New England has not used these new resources for calculating the system LOLE. For the years beyond 2011, ISO New England has assumed that the qualified existing resources for 2011 will continue to be in-service to participate in the subsequent Forward Capacity Auctions. As shown, New England will have adequate resources to meet the reliability needs for 2012 and 2013.

Table 7 LOLE Results Based on Reference Load Forecast and the FCA Outcomes

Year	LOLE Evaluation			Forward Capacity Market Auction Outcomes	
	Resources Assumed (MW)	Reference Peak Load Forecast (MW)	LOLE (days/year)	Net Installed Capacity Requirement (MW) ²³	Amount of Resources Procured in the Auction (MW)
2009	33,280	28,480	0.036	31,613	N/A
2010	34,033	28,955	0.027	32,305	Between 32,305 and 34,033
2011	34,756	29,405	0.032	32,528	Auction to be conducted in December 2008
2012	34,756	29,820	0.045	33,209	Auction to be conducted in October, 2009
2013	34,756	30,190	0.060	33,702	Auction to be conducted in August, 2010

²³ Net Installed Capacity Requirement is the amount of installed capacity needed to meet the New England resource adequacy criterion of 0.1 days per year LOLE. The values for 2010 and 2011 are the actual values filed with the FERC. The 2009, 2012 and 2013 values are representative values used for planning purposes.

5.2. BASED ON HIGH LOAD FORECAST

ISO-NE also has analyzed the system resource adequacy under a higher than expected load forecast, which would primarily occur due to higher economic growth. Table 8 shows the LOLE results based on the high load forecast, while using the same resource assumptions as for the reference load forecasts.

Table 8 LOLE Results Based on High Load Forecast

Year	Resources Assumed (MW)	High Load Peak Forecast (MW)	LOLE (days/year)
2009	33,280	28,585	0.039
2010	34,033	29,260	0.037
2011	34,756	29,925	0.049
2012	34,756	30,565	0.080
2013	34,756	31,155	0.123

The results of the high load forecast, with the same resource assumptions, show that New England would meet the NPCC resource adequacy planning criterion through 2012 but would need approximate 300 MW of additional resources to meet that criterion in 2013. Accounting for the over 7,000 MW of new resources that have shown interest and have qualified to participate in the FCA for 2011, there is a total of 41,875 MW of potential resources available in New England in the near future to serve reliability needs, well above the MW amount required to meet the LOLE criterion for 2013 associated with the high load forecast.

5.3. MECHANISMS TO MITIGATE POTENTIAL RELIABILITY IMPACTS OF UNCERTAINTY

Under the FCM, the Installed Capacity Requirement is forecasted and purchased three years ahead of the commitment period, based on ISO New England's assumed system conditions three years into the future. The FCM design recognizes that system conditions can change and uncertainties exist in load forecasts, resource ratings and availability, as well as transmission topology. The FCM construct provides measures to mitigate the reliability impacts that might be caused by these potential uncertainties through a series of annual "reconfiguration auctions" conducted prior to each commitment period. These annual reconfiguration auctions will be held in each subsequent year after the FCA for each commitment period. For each such subsequent reconfiguration auction, the ISO will recalculate the Installed Capacity Requirement using the updated forecast of resources and loads. If the recalculated capacity needs are higher than the latest amount of resources purchased for the designated period, ISO New England will purchase additional resources to meet the revised needs in the reconfiguration auctions.

6.0 PLANNED RESOURCE CAPACITY MIX

Figure 3 Generation Capacity Mix By Primary Fuel Type, 2009 Summer Rating (MW and %)

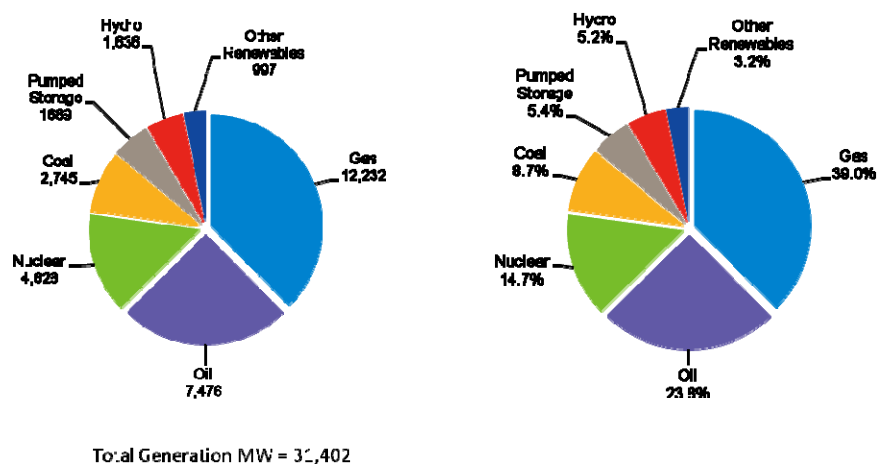


Figure 3 depicts New England's generation capacity mix by fuel type²⁴. This is expressed in terms of summer capacity ratings (MW and associated percentages) for 2009 based on the current CELT report data. Fossil-based generation continues to comprise almost 73% of the installed capacity within the region, with natural-gas-fired generation representing the largest amount of that fossil total, at 39% of total capacity (a total of 12,232 MW). Oil-fired generation is the second largest component at 7,476 MW, or approximately 24%. Nuclear generation accounts for 4,628 MW, or approximately 15%. Coal-fired generation accounts for 2,745 MW, or approximately 9%. Conventional hydro (1,636 MW) comprises approximately 5%. Pumped-storage (1,689 MW) makes up over 5% of the total installed capacity. Other renewable resources, including landfill gas (LFG), other biomass gas, refuse (municipal solid waste), wood and wood-waste solids, wind, and tire-derived fuels, total approximately 997 MW and represent about 3% of the total installed capacity.

6.1. DISCUSSION OF RELIABILITY IMPACTS FROM FUEL SUPPLY AND TRANSPORTATION

Fuel supply vulnerability is not a concern for any of the power plant fuels other than natural gas. Water availability for hydro generation has never been a concern because the New England region has seldom experienced extreme droughts, and because such resources make up a small percentage of the New England generation. Oil-fired plants, which represent only a small portion of the overall generation within New England, typically have multiple days of on-site fuel oil storage. There are no hydrological or fuel oil supply problems anticipated for New England during the study period.

Coal is primarily imported via ocean-going transport and is procured through a combination of spot-market, medium- and long-term contracts. Aside from weather-related shipping delays, coal

²⁴ The 1,820 MW of demand resources are not reflected in the mix.
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can be readily stored and stockpiled within the region. There are no coal supply or delivery problems anticipated for New England during the study period.

During the winter, however, New England's natural gas-fired generators directly compete for both finite supply and transportation, with the regional core natural gas markets (i.e., for space heating needs). During winter peak load periods, the combined capacity of all regional natural gas pipelines may not be sufficient²⁵ to serve the coincident demands from both the gas and electricity sectors. To address possible natural gas shortages during extreme cold winter weather, ISO-NE has developed a "Cold Weather Operating Procedure"²⁶ that can be implemented to help mitigate the loss of operable generating capacity, through a series of steps that include: 1) closely monitoring the regional gas supply situation, 2) communicating routinely with regional gas control, and 3) advancement of some electric market bidding timelines. Through a series of recent enhancements, ISO-NE's markets, including FCM, the Energy Market, and the Forward Reserve Market (FRM), financially reward the operation of resources when they are needed the most by the system. These mechanisms should also provide incentives for the conversion of single-fuel, gas-only units to dual-fuel capability in addition to promoting the procurement of firm gas supply and transportation contracts. Assets owners will determine which business model to implement to capture the benefits of these financial incentives.

ISO-NE's Operating Procedure No. 21, Action During An Energy Emergency²⁷ (OP-21), establishes criteria and guides for actions in anticipation of and during "energy emergencies" as triggered by the ISO and as implemented by the ISO and the Local Control Centers. Energy emergencies may occur as a result of sustained national or regional shortages in power plant fuel availability (i.e. deliverability, availability or embargo). Such shortages of power plant fuel may come in many forms, including, but not limited to: severe drought, interruption to availability or transportation of natural gas, liquefied natural gas (LNG), oil, or coal. In response to a projected energy emergency, the ISO will take necessary actions to commit, schedule, and dispatch the system in such a way as to preserve pre-inventoried fuel supply within the region, to minimize the loss of operable generating capability due to shortage of fuels.

In addition to these operating procedures and market incentives, the completed and proposed expansion projects on the regional natural gas supply and delivery infrastructure will also help to reduce the gas supply risks for New England. New LNG facilities offer the most promise for increased gas supply. A new land-based terminal, Canaport, in Saint John, New Brunswick, soon will allow new supplies of gas to flow south into New England markets. In addition, the Northeast Gateway Deepwater Port (an offshore terminal) vaporized its first cargo into the New England gas grid in May 2008. Several other regional LNG terminals have been proposed, but various permitting issues have delayed their construction.

6.2. DISCUSSION OF POTENTIAL RELIABILITY IMPACTS DUE TO ENVIRONMENTAL REGULATIONS

New and stricter federal, regional, and state environmental regulations and related initiatives that are being implemented over the next five years could affect the operation and planning of fossil-fueled electric generators throughout the Northeastern United States. In New England, the major

²⁵ This was definitely true in the past, but just as recently as this year, the regional natural gas grid has experienced a multitude of expansion, from both supply side projects to bi-directional transportation expansion. This statement may not be accurate in the near future.

²⁶ Reference Appendix H of Market Rule #1.

²⁷ http://www.iso-ne.com/rules_proceeds/operating/isone/op21/op21_rto_final.pdf
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regulations affecting power plants deal with meeting: 1) the Regional Greenhouse Gas Initiative (RGGI), 2) NOx regulations to meet the National Ambient Air Quality Standard (NAAQS) for ozone, 3) the periodic renewal of water permits for power plant cooling water intake and discharge flows, and 4) mercury regulations. These regulations are summarized in Table 9. These regulations could have secondary impacts on system reliability but it is anticipated that their principal impact on power generators and the system will be economic.

Table 9 Major Environmental Regulations and Initiatives Affecting New England Generators

Regulation/ Initiative	Description	Area/Units Affected	Date to be Implemented	Comments
RGGI CO2 emissions Cap	Voluntary 188.1 million ton CO2 cap on fossil plants 25 MW and greater	Ten states including New England	2009	First compliance period ends 2011. Allows emission allowance trading
EPA Clean Air Interstate Rule (CAIR)	Sets lower NOx emissions cap over broader region	28 states including CT and MA	Was 2009	CAIR vacated in July 2008 by Court decision. May be reinstated or transformed into legislation
High Electric Demand Days (HEDD) NOx emissions	Lowers NOx emission rates on residual oil units in two steps	CT	2013 and 2015	NY and other Mid-Atlantic also have HEDD regs
Intake and discharge water permit renewals	NPDES permits are renewed every 5 years. New performance standards will be cooling towers	All plants	When permit expires	Current EPA backlog may allow longer interval before renewal
Mercury emission reductions	EPA Clean Air Mercury Rule (CAMR); State regulations	Coal plants in CT, MA and NH	2008 in CT and MA; 2013 in NH	CAMR vacated by Court decision in February 2008

Starting in 2009, RGGI will impose a cap on CO2 emissions from fossil units 25 MW and larger in all of New England and four other states. Ozone compliance over a broad eastern region of the U.S. is requiring tighter NOx caps and emission rates on some New England units. Also for ozone compliance, Connecticut is setting stricter NOx emission rates on residual oil units to meet voluntary High Electric Demand Day (HEDD) NOx reductions. In addition, a power plant’s water intake and discharge permit²⁸ must be renewed every five years. To address power plant cooling water intake and discharge impacts on the aquatic environment, the Environmental Protection Agency (EPA) has implemented a new standard for power plant permit renewal based on utilizing cooling towers or their equivalent to protect the aquatic environment. As most regional power plants have once-through cooling, the renewal of these permits could require installation of cooling towers or some equivalent operating change or add-on controls. Finally, state regulations reducing mercury emissions from coal-fired power plants are in effect in three New England states.

The Renewable Portfolio Standards (RPS), which are established in five of the six New England states (except Vermont), and are intended to stimulate the development of new renewable resources to achieve a more diverse and “clean” generation portfolio, may also present impacts on the operation of power plants in the New England system. Several states also have other related requirements for the growth of renewable resources and energy efficiency outside the usual RPS structure. In its 2008 Regional System Plan, ISO-NE has conducted analysis to project the additional needs for renewable resources in the next 10 years based on these RPS requirements. ISO-NE also assessed whether current projects in the ISO’s Generation Interconnection Queue would be sufficient to meet the RPS requirements taking into account

²⁸ The permit is the National Pollution Discharge Elimination Permit (NPDES) and is renewed every five years.

²⁹ http://www.iso-ne.com/regulatory/ferc/filings/2008/oct/er09-5-000_10-1-08_dri_.pdf

contributions from other RPS compliance sources. As of March 15, 2008, there was a total of 43 renewable energy projects in the ISO Generator Interconnection Queue that could be eligible to meet an aggregate of the states' RPS requirements. The projects include small hydro, landfill gas, biomass, wind and fuel cells. If all projects in the queue were built, it is estimated that these projects would approximately meet the total 2016 need for the new renewable resources.

Compliance with these environmental regulations could affect system reliability if there is a need to:

- Limit the operation of specific generating units as a last compliance alternative to reducing emissions,
- Take extensive generator outages to add, retrofit, or upgrade environmental emission control equipment, or,
- Retire specific generating units that cannot economically comply with the environmental regulations.

In its 2008 Regional System Plan, ISO-NE has conducted economic analysis to evaluate the emission output under a series of scenarios for the next 10 years. The results indicated that with the use of offsets that could be obtained in the offset market, the emission compliance will be achievable for the next five years under all scenarios.

ISO-NE believes the major effect of these and other regulations will be mostly economic with the addition of emission controls at affected power plants. These controls will likely translate into higher wholesale market electric energy prices.

ISO-NE already has operating and planning procedures in place to minimize any adverse reliability effects on system operations. In addition, ISO-NE is monitoring the promulgation of environmental regulations through its annual Region System Plan to identify potential resource adequacy effects on the bulk power system.

In summary, new environmental regulations will likely have an economic impact on the New England generators and therefore increase the wholesale market price. Any possible reliability threat seems unlikely over the next five years, and ISO's planning and operating procedures will help anticipate and mitigate any potential threat.

6.3. DISCUSSION OF POTENTIAL RELIABILITY IMPACTS FROM INTEGRATION OF RENEWABLE AND DEMAND RESOURCES

The ISO anticipates that approximately 80 MW of larger-scale commercial wind farms will be operational by the end of 2008 and dispatched by ISO operators. At the current levels of in-service wind facilities (about 11 MW in nameplate rating), and the expected installation of a few hundred megawatts of nameplate capacity from future facilities over the next five years, ISO-NE does not anticipate any major reliability impacts from the integration of these wind resources into system operations.

Larger amounts of demand resources have emerged from the FCM auction process. A total of 2,234 MW of demand resources cleared in the first FCA for the delivery year 2010/11, of which, about 700 MW represents passive demand-response resources, and the remainder, about 69%, represents active demand-response resources. When all the resources that have cleared in the first

FCA are added to all the demand resources that have submitted qualification packages to participate in the second FCA and that could clear in the upcoming auction for the 2011/12 delivery year, over 3,500 MW of demand resources could be available to meet New England resource needs. This amount represents almost 11% of the total installed capacity resources in the New England bulk electric power system by 2011. Although this level of demand resources provides many benefits, efficiently integrating this magnitude of demand resources into the bulk power system while maintaining system reliability can be challenging. More demand resources within the supply base of ICR may result in more frequent operation of active demand resources, including operation during the off-peak months. Revised and/or new market rules are required to meet operational challenges stemming from the dispatch of active demand resources, to facilitate demand-resource participation in the FCM, to use critical-peak resources, and to add necessary technical infrastructure for active demand resources. New market rules also are needed as a risk-management strategy to ensure reliable operation of demand resources. ISO-NE has filed with FERC modified market rules and operating procedures to address the operating and market issues raised by the high level of demand resources that will need to be integrated into the New England bulk electric power system.

APPENDIX

A Description of Resource Reliability Model

GE MARS uses a sequential Monte Carlo simulation to compute the reliability of a system comprised of a number of interconnected areas containing generation and load. This Monte Carlo process simulates the year repeatedly (multiple replications) to evaluate the impacts of a wide-range of possible random combinations of generator outages. The transmission system is modeled in terms of transfer limits (constraints) on the interfaces between interconnected areas.

Chronological system histories are developed by combining randomly generated operating histories of the generating units and inter-area transfer limits with the hourly chronological loads. For each hour of the year, the program computes the isolated area margins based on the available capacity and demand in each area. GE MARS then uses a transportation algorithm to determine the extent to which areas with negative margin can be assisted by areas having positive (excess) margin, subject to the available transfer constraints between the areas. The program collects the statistics for computing the reliability indices, and proceeds to the next hour. After simulating all of the hours in the year, the program computes the annual indices and tests for convergence. If the simulation has not converged to an acceptable level, it proceeds to another replication of the study year; otherwise, it moves on to the next study year.

A.1.1 Load Model

A.1.1.1 Hourly Loads

GE MARS employs an 8760-hour chronological subarea load model. The load model currently used relies on an actual year of historical loads of 2002. This model is then scaled up to the summer peak for the future years being analyzed.

A.1.1.2 Load Forecast Uncertainty

The load forecast uncertainty was modeled on a seasonal basis, which accounts for the uncertainty due to weather variations.

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

All the demands of entities within NEPOOL are modeled. The Maine Public Service (MPS) company demand is not modeled in this review because it is currently not a part of the ISO-NE Planning Authority area.

A.1.1.4 Demand Side Management Programs

For 2009, modeled in the calculation are Demand Response resources in the Reliability Program category. These resources provide real time peak load relief within 30-minutes or 2-hours of a request by ISO New England, during or in anticipation of expected operable capacity shortage conditions, where ISO-NE plans on implementing Operating Procedure No. 4, *Actions During a*

Capacity Deficiency. Also included in the modeling are the profiled resources, which provide load relief in under 2-hours but do not have interval meters installed. Other Demand Resources (ODR), a Demand Resource group primarily consisting of Energy Efficiency programs whose impacts were historically incorporated into the load forecasts, are now extracted from the load forecast, and modeled as a resource. These demand resources are treated and paid in the same manner as traditional supply resources, and are part of the resource base used to satisfy the Installed Capacity Requirement.

Starting in 2010, the first commitment period of the FCM, all five categories of demand resources are included in the reliability modeling: the On-Peak, Seasonal Peak, Critical Peak, Real-Time Demand Response and Real-Time Emergency Generation.

- On-peak Demand Resource is a non-dispatchable measure that is not weather sensitive and its reduction in load will be measured during the hours ending 14:00 through 17:00, Monday through Friday on non-holidays during the months of June, July and August and the hours ending 18:00 through 19:00, Monday through Friday on non-holidays during the months of December and January.
- Seasonal Peak Demand Resource is a non-dispatchable, weather-sensitive measure and its reduction in load will be measured during hours in which the actual, Real-Time hourly load for Monday through Friday on non-holidays, during the months of June, July, August, December, and January, as determined by the ISO, is equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.
- Critical Peak Demand Resource is a measure that can be dispatched by the project owners and must reduce load during Forecasted Peak Hours and Real-Time Demand Resource Dispatch Hours. Demand Resource Forecast Peak Hours are the hours, or portions thereof, in which, absent the dispatch of Critical Peak Demand Resources and Real-Time Demand Response Resources, Load Zone or system-wide implementation of the action of ISO New England Operating Procedure No. 4 where the ISO would have begun to allow the depletion of Thirty-Minute Operating Reserve is forecasted in the ISO's most recent next-day forecast, and the ISO notifies the Market Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours before 22:00 on the day before the relevant Operating Day. Beginning on June 1, 2011, Demand Resource Forecast Peak Hours are the hours, or portions thereof, in which, absent the dispatch of Critical Peak Demand Resources and Real-Time Demand Response Resources, Dispatch Zone, Load Zone, or system-wide implementation of the action of ISO New England Operating Procedure No. 4 where the ISO would have begun to allow the depletion of Thirty-Minute Operating Reserve is forecasted in the ISO's most recent next-day forecast, and the ISO notifies the Market Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours before 22:00 on the day before the next Operating Day. In accordance to the recently modified market rules²⁹, this Critical Peak Demand Resource category will be eliminated by the 2012/13 Capacity Commitment Period. Existing Critical Peak Demand Resources may convert to any other Demand Resource type (except for the Real-Time Emergency Generation type) by submitting an Updated Measurement and Verification Plan to reflect

the change in Demand Resource type prior to the 2012/13 Capacity Commitment Period, or choose to retire.

- Real-Time Demand Response Resource is a type of Demand Resource that is comprised of installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that: (i) curtail electrical usage in response to a Dispatch Instruction; and (ii) continue curtailing electrical usage until receiving Dispatch Instructions to restore electrical usage. Such measures include Load Management and Distributed Generation. The period of curtailment shall be consistent with Real-Time Demand Response Event Hours.
- Real-Time Emergency Generation Resource is Distributed Generation whose Federal, State and/or local air quality permits limit operation in response to requests from the ISO to the times when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement. A Real-Time Emergency Generation Resource must be capable of: (i) curtailing its end-use electric consumption from the New England grid within 30 minutes of receiving a Dispatch Instruction; and (ii) continuing that curtailment until receiving a Dispatch Instruction to restore consumption. The amount of Emergency Generators used to meet the ICR is currently limited to 600 MW, as stipulated in the market rules.

A.1.2 Resource Unit Representation

A.1.2.1 Unit Ratings

A.1.2.1.1 Definition

For the year 2009, ratings for the existing generating units were based on ISO-NE's Seasonal Claimed Capability (SCC) information as reported in the April 2008 CELT report. Claimed capability is the demonstrated maximum dependable load carrying capability, in megawatts, of such units, excluding capacity required for station service use. The summer rating period runs from June 1 through September 30, and the winter rating period runs from October 1 through May 31. For demand resources, the rating was based on the Enrolled Capacity value at the time the asset is registered, which is the amount the asset is expected to deliver in an hour.

For the years of 2010 and beyond, the ratings of all resources were based upon their seasonal Qualified Capacity values that are determined in accordance with the FCM market rules.

A.1.2.1.2 Procedure for Verifying Ratings

- Seasonal Claimed Capability of Generating Units

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 unit is then required to hold the output at its SCC for a predefined time period. 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 its

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) located at: http://www.iso-ne.com/rules_proceeds/isone_mnls/index.html.

- Demand Reduction Value from Demand Resources

The demand reduction values from demand resources are based on the Enrolled Capacity value that is expected to deliver in an hour at the time an asset is registered during the FCM transition period. However, if during an audit or OP4 event the asset performs at a value lower than the Enrolled Capacity, the capacity payment will be subsequently reduced to that value. If the asset performs at an amount higher than the Enrolled Capacity, the capacity payment remains the same based on the Enrolled Capacity value. A higher Enrolled Capacity value may be requested based on historical performance. The ISO evaluates these requests and either approves or denies them. Related details of demand resources are documented in the New England Manual for Load Response Program, M-LRP located at : http://www.iso-ne.com/rules_proceeds/isone_mnls/index.html.

- Qualified Capacity Value under FCM

The determination of the Qualified Capacity value of a resources for participation in the FCA is outlined in the Section III. 13 – Forward Capacity Market of Market Rule 1 located at: http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

The summer Qualified Capacity of a Generating Resource is calculated as the median of the most recent five summer Seasonal Claimed Capability (SCC) ratings with only positive, non-zero ratings included in the calculation.

The seasonal Qualified Capacity for Intermittent Power Resources, will be calculated as the median of the net output during the Seasonal Intermittent Reliability Hours, of the most recent five summer periods.

The summer Qualified Capacity of a Demand Resource will be rated on the summer seasonal Demand Reduction Value calculation which is dependent upon the Demand Resource type.

A.1.2.2 Unit Unavailability Factors

A.1.2.2.1 Unavailability Factors Represented

Forced outage rates, planned outages, and maintenance outages are represented for each resource in the reliability assessment.

A.1.2.2.2 Sources of Unavailability Factors

A 5-year, historical average of unit-specific forced outage assumptions is determined for each generating unit qualified as an Existing Generating Capacity Resource, using its individual unit data of monthly EFORD³⁰ values from NERC's Generating Availability Data System (GADS). NERC GADS data submitted by generators to ISO-NE for the months of March 2003 through

³⁰ The calculation methodology of EFORD can be found in ISO-NE Manual 20 at http://www.iso-ne.com/rules_proceeds/isone_mnls/M20/index.html.

February 2008 is used to create an EFORd value for each unit that submits such data. NERC Class Average data is used as a substitute for units that do not submit GADS data.

ISO-NE uses a 5 year historical average of actual generation during the daily peak periods as the expected Intermittent Power Resources' rating. This resource rating approach takes into account the resources' physical and fuel availability. No additional availability factors are considered for these type of resources.

Demand Resources in the Other Demand Resources, On-peak and Seasonal Peak categories are considered as 100% available in the models. These categories consist of passive resources such as energy efficiency which are considered as always “*in service*” and as such are 100% available. Performance of Demand Resources in the Real-Time Demand Response and Critical Peak categories are measured by actual response during all historical events including audits and OP 4 events for all years of the current Demand Response programs (2003-2007). To calculate the percent historical performance, the actual load curtailed or generation provided during each event is divided by the MW of resources enrolled within the program at the time of the event. The assumption for Real-Time Emergency Generator is based on the average of the 2003-2007 audit and OP 4 event response for all Real-Time Emergency Generators enrolled as an OP 4 Action 12 Emergency Generating Resources.

A weekly representation of a generator's scheduled outages is calculated for each unit, based on a 5-year historical average.

A.1.2.2.3 Maturity Consideration

NERC Class Average data is used as a substitute for immature units and new additions.

A.1.2.2.4 Tabulation of Unavailability Factors

Table 10 and 11 show the average unavailability factors used in this reliability assessment.

Table 10 Generating Resource EFORd and Maintenance Weeks by Category

Unit Type	Assumed Weighted EFORd(%)	Assumed Maintenance Weeks
Fossil	7.56	5
Combined Cycle	5.17	5
Diesel	6.51	1
Combustion Turbine	6.55	2
Nuclear	1.56	3
Hydro	1.65	3
Others	5.18	0
System	5.11	4

Table 11 Demand Resources EFORd Assumptions by Category

Type	Assumed Weighted EFORd(%)	Assumed Maintenance Weeks
Other Demand Resources	0.00	0
On-Peak Demand Resources	0.00	0
Seasonal Peak Demand Resources	0.00	0
Critical Peak Demand Resources	24.00	0
Real-Time Demand Response	24.00	0
Real-Time Emergency Generator	21.00	0

A.1.2.3 Imports and Exports Representation

Table 12 summarizes the capacity imports and exports with neighboring systems assumed for this assessment.

Table 12 Capacity Import and Export Assumptions (MW)

	2009	2010	2011 - 2013
Hydro-Québec Import	310	200	280
New York Import (via AC lines)	91	734	725
New York Export (via Cross Sound Cable)	343	100	100

A.1.2.4 Retirements & Deactivations

In this review, no retirement and deactivations are assumed.

A.1.3 Representation Of Interconnected Systems

New England's directly interconnected neighboring bulk power systems are represented by tie benefits in this comprehensive review. These tie benefits are derived based on results of studies conducted with the GE MARS program. In these tie benefit studies, all the interconnected Areas are assumed to be at the 0.1 days/year resource adequacy criterion simultaneously. The Area's load, resource (including load and/or capacity relief assumed available from implementing emergency operating procedures) and transmission interface transfer limits are based on data that each Area has provided to NPCC for its studies. ISO-NE updates its tie benefit studies whenever it deems necessary. The tie benefit assumptions used in this review are based on results of studies conducted in 2003, 2007 and 2008. Table 13 summarizes the tie benefit assumptions for this review.

The tie benefit assumptions for 2009 are based on the 2003 Tie Benefit Study³¹. For 2010, the tie benefits assumptions are based on the results of the 2007 study³². For 2011 and beyond, the tie benefit assumptions are based on the results of the 2008 study³³. While the total tie benefits assumed for each year of the comprehensive review period are quite consistent, the tie benefits

³¹ http://www.iso-ne.com/genrtion_resrcs/reports/nepool_oc_review/2003/tiebenefit2003summary.pdf

³² Related study results can be found in the Power Supply Planning Committee materials located at: http://www.iso-ne.com/committees/comm_wkgtps/reblty_comm/pwrsuppln_comm/mtrls/2007/index.html

³³ Related study results can be found in the Power Supply Planning Committee materials located at: http://www.iso-ne.com/committees/comm_wkgtps/reblty_comm/pwrsuppln_comm/mtrls/2008/index.html

assumed obtainable from each of New England’s neighboring Area show variations. These variations occur from 2009 through 2011 and are results of changes in expected system conditions and the allocation methodology applied to determine individual Area’s contribution to the total tie benefits. For a complete description of the current tie benefits calculation methodology, please review the ISO-NE filing with the Federal Energy Regulatory Commission³⁴.

Table 13 Assumed Tie Benefits From Neighboring System (MW)

Neighboring System	2009	2010	2011 - 2013
Hydro-Québec	1,200	1,400	911
New Brunswick	200	360	716
New York	600	100	173
Total	2,000	1,860	1,800

A.1.4 Modeling of Limited Energy Sources

New England’s pumped storage and hydro-electric 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)

A description of the DSM programs were presented in Section A1.1.4.

A.1.6 Modeling of Resources

Modeling of resources was as described in the above sections.

A1.7 Other Assumptions

Consistent with the ISO-NE’s Regional System Plan, the New England system was modeled as 13 interconnected sub-areas, with predefined 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, *Reliability Standards for the New England Power Pool*, and NPCC Document A-2³⁵, *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

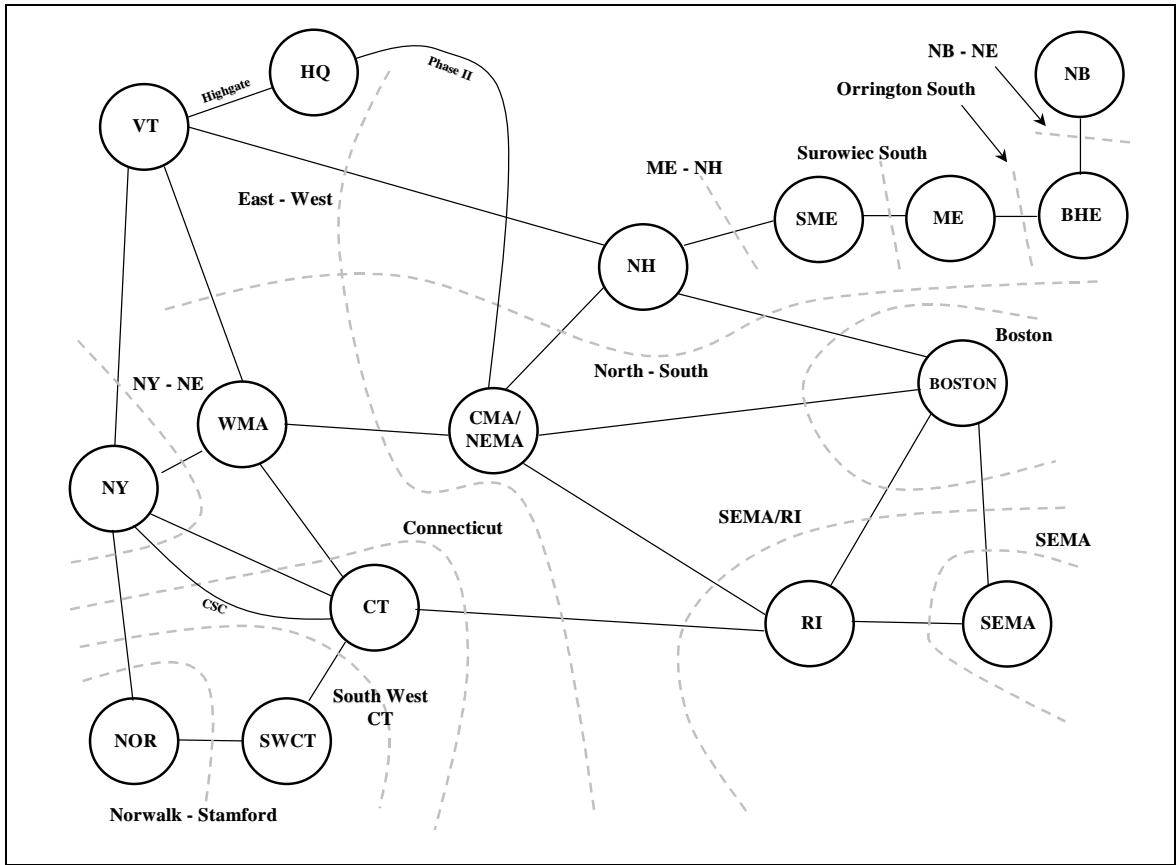
³⁴ http://www.iso-ne.com/regulatory/ferc/filings/2008/jul/er08-41-____07-31-08_tie_benefits_filing.pdf

³⁵ <http://www.npcc.org/documents/regStandards/Criteria.aspx>
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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 transmission interfaces used in the reliability analysis represent potential limiting areas of New England's transmission system, which may become constrained under a variety of system conditions, generation patterns, or transmission topology. 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.

Figure 4 New England Sub-Area Representation



Sub-areas

- BHE - Northeastern Maine
 - ME - Western & Central Maine / Saco Valley, New Hampshire
 - SME - Southeastern Maine
 - NH - Northern, Eastern, & Central New Hampshire / Eastern Vermont & Southwestern Maine
 - VT - Vermont / Southwestern 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 - Northern and Eastern Connecticut
 - SWCT - Southwestern Connecticut
 - NOR - Norwalk / Stamford, Connecticut
- NB, HQ and NY represent the New Brunswick, Hydro-Québec and New York balancing authority respectively.

Interface Limits (MW)

<u>Interface or Interface Group</u>	<u>Interface Limit (MW)</u>
New Brunswick to NE	1,000
Orrington South	1,200
Surowiec South	1,150
Maine – NH	1,600
	1,575 (Year 2011)
	1,550 (Year 2012)
	1,525 (Year 2013)
North to South	2,700
Boston Import	4,600
	4,900 (Year 2009)
SEMA Export	No Limit
SEMA / RI Export	3,000
	3,300 (Year 2013)
East to West	2,800
	3,500 (Year 2013)
Connecticut Import	2,500
	3,600 (Year 2013)
Southwestern CT Import	2,350
	3,650 (Year 2010)
Norwalk / Stamford Import	1,300
	1,650 (Year 2010)
New York / New England (Summer)	1,400
New York / New England (Winter)	1,700
HQII Import	1,400
Highgate Import	200
CSC	346