2010 Annual Markets Report

Internal Market Monitor
June 3, 2011

Preface

The Internal Market Monitor (IMM) of ISO New England (ISO) publishes an Annual Markets Report (AMR) that assesses the state of competition in the wholesale electricity markets operated by the ISO. The *2010 Annual Markets Report* covers the ISO's most recent operating year, January 1 to December 31, 2010. The report addresses the development, operation, and performance of the wholesale electricity markets administered by the ISO and presents an assessment of each market on the basis of market data, performance criteria, and independent studies.

This report fulfills the requirement of *Market Rule 1*, Section III.A.12.3, Appendix A, *Market Monitoring, Reporting, and Market Power Mitigation*:

> The [IMM] will present an annual review of the operations of the New England markets, which will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, NCPC [Net Commitment-Period Compensation] costs, and the performance of the Forward Capacity Market and FTR [Financial Transmission Rights] auctions. The review will include a public forum to discuss the performance of the New England markets, the state of competition, and the ISO's priorities for the coming year.[1]

The IMM submits this report simultaneously to the ISO and the United States Federal Energy Regulatory Commission (FERC) per FERC order:

> The Commission has the statutory responsibility to ensure that public utilities selling in competitive bulk power markets do not engage in market power abuse and also to ensure that markets within the Commission's jurisdiction are free of design flaws and market power abuse. To that end, the Commission will expect to receive the reports and analyses of an RTO's [Regional Transmission Organization's] market monitor at the same time they are submitted to the RTO.[2]

The External Market Monitor (EMM) also publishes an annual assessment of the ISO New England wholesale electricity markets. The EMM is external to the ISO and reports directly to the board of directors. Like the IMM's report, the External Market Monitor's report assesses the design and operation of the markets and the competitive conduct of the market participants.

This report of the IMM presents the most important findings, market outcomes, and market design changes of New England's wholesale electricity markets for 2010. A summary of the data and outcomes is included in Section 1. To aid the reader in understanding the report's findings, an overview of the New England electricity markets, how they function, and market monitoring is presented in Section 2. Section 3 through Section 7 include more detailed discussions of each of the markets, market results, and the IMM's analysis and recommendations. An appendix (Section 8) provides additional data on the markets. A list of acronyms and abbreviations also is included. Key terms are italicized and defined within the text and footnotes.

[1] *ISO New England Inc. Transmission, Markets, and Services Tariff* (ISO tariff), Section III.A.12.3, *Market Rule 1,* Appendix A, "Market Monitoring, Reporting, and Market Power Mitigation" (April 15, 2011), http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

[2] FERC, *PJM Interconnection, L.L.C. et al., Order Provisionally Granting RTO Status*, Docket No. RT01-2-000, 96 FERC ¶ 61, 061 (July 12, 2001).

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Section 1
Summary of New England's
Wholesale Electricity Markets in 2010

The core responsibilities of the ISO's Internal Market Monitor (IMM) include reviewing the competitiveness of the wholesale electricity markets, reporting on market outcomes, and recommending improvements to the market design. The *2010 Annual Markets Report* addresses the development, operation, and performance of the wholesale electricity markets administered by ISO New England (ISO) and presents an assessment of each market on the basis of market data and performance criteria.

This section summarizes the region's wholesale electricity market outcomes for 2010, important market issues and the IMM's recommendations for addressing these issues, the overall competitiveness of the markets, and market mitigation and market reform activities. A discussion of how the markets work and of the IMM's market oversight role is included in Section 2. Section 3 through Section 7 contain a more detailed discussion of the 2010 market results and the IMM's operation. Section 8 is an appendix of additional data. A list of abbreviations and acronyms is included at the end of the report. Key terms are italicized and defined within the text and footnotes.

1.1 Summary of Market Outcomes

Over the long run, competitive and efficient electricity markets provide the incentives to maintain an adequate supply of electric energy at prices consistent with the cost of providing it. On the basis of its review of market outcomes and related information, the IMM concludes that the wholesale electricity markets in New England operated competitively in 2010. Market concentration is low, and energy prices remain at levels consistent with the short-run marginal cost of production. June 1, 2010, marked the beginning of the first commitment period for resources purchased through the Forward Capacity Auction (FCA). These resources were able to support reliable operation through a summer period with high loads and the extended, unexpected outage of a large resource. Market outcomes were influenced by increases in fuel price, less hydroelectric energy, and higher loads, especially during the summer months. These factors caused energy, congestion, and reliability costs to increase over 2009 levels.

In wholesale electricity markets, the price is set by the marginal resource (i.e., the one that will serve the next increment of load). In New England, the marginal resource typically is a natural gas unit, but when loads are high, the marginal resource may be a more expensive oil unit. Compared with 2009, average prices for all major fuel types were higher in 2010. Natural gas prices increased by 9%, fuel oil prices by about 30%, and coal prices by 27%. These fuel-price increases translate directly into higher costs of electric energy. The effect of higher fuel prices was exacerbated by hot weather and increased economic activity that caused load to increase by 3.1% in 2010 and more expensive units to operate, which resulted in oil units setting prices (at high levels) more frequently than in 2009. These factors caused the average annual price of wholesale electric energy to increase by 19%, from $42.89/megawatt-hour (MWh) in 2009 to $50.98/MWh in 2010. The all-in cost of wholesale electric energy, which includes capacity and ancillary service payments as well as energy costs, rose from $7.5 billion in 2009 to $8.5 billion in 2010, an increase of 12%.[3]

A combination of high loads and forced outages during two days in 2010 caused unusual operating conditions. On June 24, total system capacity dropped below the level needed to meet load plus operating reserve, and several actions of the ISO's Operating Procedure No. 4 (OP 4), *Action during a Capacity Deficiency*, were called.[4] This was the first time demand resources procured through the Forward Capacity Market (FCM) were dispatched.[5] While in aggregate the response was good, most resources either overperformed or underperformed. On September 2, a large generating unit tripped, forcing the operators to dispatch all capacity available within 10 minutes to restore the area control error (ACE) to precontingency levels.[6] The ISO dispatched more than enough megawatts (MW) needed to cover the contingency; however, generator response to the dispatch instructions was inadequate to restore the ACE in a timely manner. The IMM's review of these events has led to several recommendations and the identification of areas for further review.

The Forward Capacity Market continues to provide sufficient resources to meet the region's resource adequacy requirements. The fourth Forward Capacity Auction (FCA #4) was held in August 2010 and, like the previous three FCAs, cleared at the auction floor price. The floor price for FCA #4 was $2.95/kilowatt (kW)-month and resulted in a capacity surplus of 5,374 MW. Capacity payments made to all resources in 2010 totaled $1,649 million.[7]

Net Commitment-Period Compensation (NCPC) payments in 2010 continued the trend away from payments to resources committed to meeting reliability needs (e.g. second-contingency protection or voltage needs) to those committed to ensuring that resources were sufficient to meet load plus operating reserves (economic NCPC).[8] In 2010, economic NCPC increased by 160%, from

[3] The total cost of electric energy is approximated as the product of the annual net energy load (NEL) for the region and the average annual real-time locational marginal price (LMP) at the Hub. NEL is calculated as total generation (not including the generation used to support pumping at pumped-storage hydroelectric generators), plus net imports. LMPs are identified at 900 pricing points (*pnodes*) on the system as a way for wholesale electric energy prices to efficiently reflect the value of electric energy at different locations based on the patterns of load, generation, and the physical limits of the transmission system. The *Hub* is a collection of pnodes that represents an uncongested price for electric energy. *Load zones* are aggregations of pnodes within specific areas.

[4] Operating Procedure No. 4, *Action during a Capacity Deficiency* (December 10, 2010), http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html.

[5] A *demand resource* is a source of capacity whereby a consumer reduces the demand for electricity from the bulk power system in response to a request from the ISO to do so for system reliability reasons or in response to a price signal.

[6] *Area control error* is the instantaneous difference between the net actual and scheduled transfer of electric energy between two balancing authority areas, accounting for the effects of frequency bias and correction for meter error. ACE must be restored to its predisturbance value within 15 minutes, and operating reserves must be restored, as required by the disturbance control standard of NERC's Reliability Standard, BAL-002-0, "Disturbance Control Performance" (April 1, 2005), http://www.nerc.com/files/BAL-002-0.pdf.A *contingency* is the sudden loss of a generation or transmission resource. A system's *first contingency* (N-1) is when the power element (facility) with the largest impact on system reliability is lost. A *second contingency* (N-1-1) takes place after a first contingency has occurred and is the loss of the facility that at that point would have the largest impact on the system.

[7] This includes both FCM transition payments (paid before June 1, 2010) and FCM auction payments (paid after May 31, 2010). FCM transition payments replaced the Installed Capacity (ICAP) Market in December 2006 and continued until May 31, 2010. The 2010/2011 FCM commitment period began on June 1, 2010. A *capacity commitment period* is also known as a *capability year* and runs from June 1 through May 31 of the following year.

[8] *Net Commitment Period Compensation* is a method of providing "make-whole" payments to market participants with resources dispatched out of economic-merit order for reliability purposes when the costs of providing energy or reserves from the resources would otherwise exceed the revenue paid to the market participant. *Economic NCPC* arises when the

$32.6 million in 2009 to $84.7 million, while the costs associated with providing local second-contingency protection and voltage support decreased by 59%, from $22.5 million in 2009 to $9.1 million. The economic NCPC cost increases were largest beginning in May when a large flexible unit had an unexpected outage, forcing the commitment of inflexible fossil-fuel-fired units to meet load and reserves. Economic NCPC costs also were increased by the ISO's need to cover 112%, rather than 100%, of its largest contingency as 10-minute reserve because of the ISO's failure to return ACE to predisturbance levels after the loss of a large unit on September 2, 2010.[9]

The increase in economic NCPC has had an adverse impact on virtual transactions. During 2010, the gross profitability of virtual positions totaled $14 million. The total allocation of real-time NCPC charges to these positions totaled $22.2 million. Net of real-time transaction costs associated with NCPC, virtual positions realized a loss of $8.1 million.

As a result of this year's review of market outcomes and performance, the IMM makes several recommendations for changes to the market rules and has identified areas for additional analysis in 2011:

- As part of a review of the entire set of rules addressing the allocation of NCPC and to address the high costs imposed on virtual transactions by the current allocation of NCPC, the IMM recommends that the ISO revise the market rules so that real-time Net Commitment-Period Compensation charges are not allocated inappropriately to virtual transactions (see Section 3.4.7).

- To ensure that real-time prices are appropriately set and reflect supply and demand under all market conditions, the IMM recommends that the ISO review the way real-time prices are calculated.

- To ensure that assets in the Day-Ahead Load-Response Program (DALRP) are paid only for genuine load reductions (i.e., load reductions resulting from the customer taking an action), the IMM makes several recommendations regarding DALRP design, especially the calculation of each asset's baseline (or counterfactual estimate of consumption).

- Currently, an FCM shortage event occurs only if the ISO is short of 10-minute reserve for longer than 30 minutes. Because this seldom happens on the power system, very few shortage events occur. The IMM is concerned that this definition of shortage events may be too restrictive and fail to capture times during which the performance of resources in the capacity market should be measured. For example, redefining shortage events as occurring with a shortage of 10-minute reserves for much less than 30 minutes may be appropriate. The IMM will conduct additional analysis of the role of this feature in the FCM design and may recommend design changes (see Section 7.4).

- To ensure efficient and secure real-time operations, all resources must follow dispatch instructions. On June 24, 2010, the Internal Market Monitor observed that the majority of the

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total cost of committing and operating a generating resource exceeds the revenues it earns from the sale of energy at the LMP.

[9] *Ten-minute spinning reserve* (TMSR), also called *10-minute nonsynchronized reserve*, is reserve capability offered by on-line generating units able to increase output within 10 minutes in response to a contingency.

dispatched demand-response resources either underperformed or overperformed. The IMM will continue to monitor the performance of demand-response resources and may recommend design changes (see Section 7.4.4). The inability to restore ACE to precontingency levels on September 2, 2010, has highlighted the need to review the rules regarding the failure to follow dispatch and, if appropriate, to establish a definition for failing to follow dispatch for purposes other than NCPC payment and price setting.

1.2 Competitiveness of the ISO Energy Markets

To assess the competitiveness of the electric energy markets, the IMM examined two types of measures of market competitiveness: structural measures, which analyze the concentration of generation-resource ownership in the New England markets; and price-based measures, which compare wholesale market prices to the estimated cost of providing electric energy. The results of the concentration analyses show that the market is structurally competitive, and during instances when inadequate transmission or peak load levels create the possibility of anticompetitive behavior, mitigation rules provide behavior remedies. Market results show that electric energy prices reflect supplier costs to produce electric energy (i.e., largely fuel prices), which is consistent with the finding that the market is competitive. The results of these analyses are included below and in Section 3.

The structural measures used are the Herfindahl-Hirschman Index (HHI) and the Residual Supply Index (RSI).[10] The HHI of about 600 for the entire New England region for 2010 indicates the market is not concentrated at the systemwide level. This HHI is well below the 1,500 level that the US Department of Justice (DOJ) uses as a threshold measure of an unconcentrated market.[11]

The RSI results for 2010 show that output from the largest supplier was pivotal (i.e., necessary to meet demand) during 223 hours, between May and September. Figure 1-1 shows a duration curve of systemwide RSI calculations for the year. A review of the RSIs for the Connecticut (CT) and Northeast Massachusetts/Boston (NEMA/Boston) local reserve zones for May 2010 through September 2010 suggests a slightly higher level of market concentration.[12] In the CT local reserve zone, a supplier was pivotal up to 15% of the time. The NEMA/Boston local reserve zone was slightly more concentrated, with a pivotal supplier in 37% of total hours. This represents an increase from last year's value as a result of tighter local supply and demand conditions. The RSI analysis suggests that suppliers in the local reserve zones may have the ability to exercise market power. This reinforces the importance of offer-mitigation measures for import-constrained areas to deter suppliers with market power from using it to raise prices.

[10] The *Herfindahl-Hirschman Index* is a measure of market concentration based on generating capacity. The systemwide *Residual Supply Index* measures how much of the load in a given hour in megawatt-hours can be met without any capacity from the largest supplier. Suppliers that are necessary to meet demand are termed "pivotal" and can affect market prices.

[11] The Department of Justice defines markets with an HHI below 1,500 points to be unconcentrated, an HHI between 1,500 and 2,500 points to be moderately concentrated, and an HHI above 2,500 points to be highly concentrated. US Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines* (Washington, DC: US Department of Justice and Federal Trade Commission, August 19, 2010), http://www.justice.gov/atr/public/guidelines/hmg-2010.html.

[12] The region has four reserve zones—Connecticut, Southwest Connecticut (SWCT), NEMA/Boston, and the rest of the system (Rest-of-System, ROS). The *Rest-of-System* zone is the area excluding the other local reserve zones.

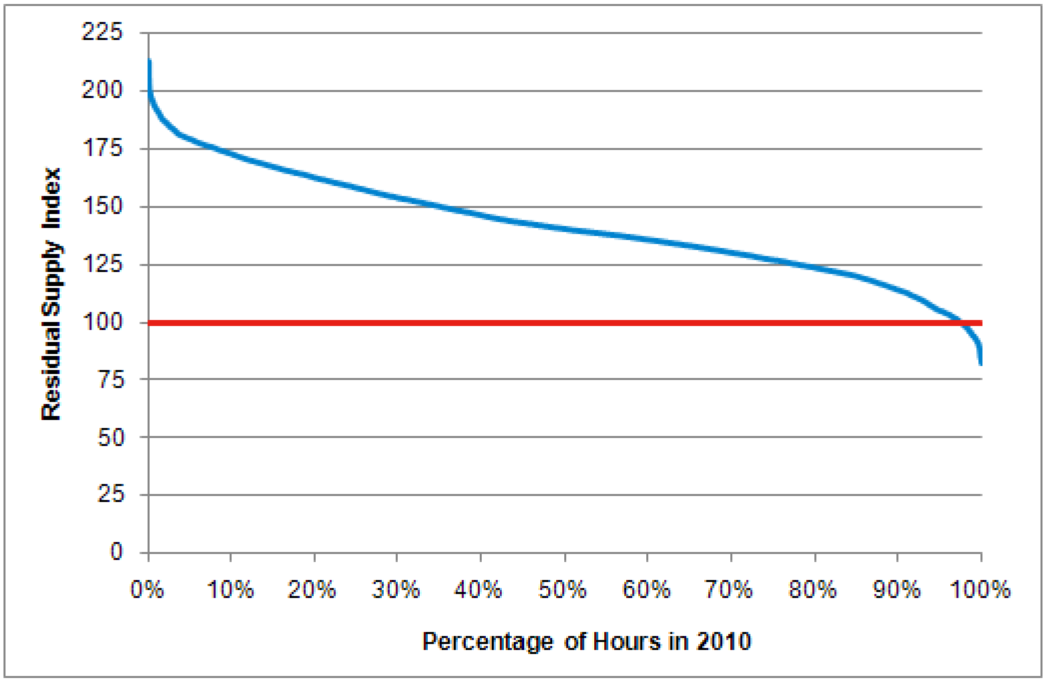

Figure 1-1: 2010 Residual Supply Index duration curve for the entire New England Market.

Note: When the RSI is below 100%, a portion of the largest supplier's capacity is required to meet market demand, and the supplier is pivotal. A pivotal supplier can drive prices above the competitive level, subject only to offer caps, mitigation measures, and the price elasticity of demand.

The price-based measure used is the competitive benchmark. The competitive benchmark model compares market prices modeled using participants' actual supply offers (offer prices) with modeled prices using IMM's estimates of short-run variable costs as supply offers (benchmark prices). For 2010, the average offer-based price is $47.52/MWh, while the benchmark price is $44.89/MWh.

The results of the competitive benchmark model are used to calculate the Quantity-Weighted Lerner's Index (QWLI), the values for which are shown in Table 1-1. The QWLI is the percentage markup of price over marginal cost, but because it is model based, it is subject to estimation error in both the model and marginal costs. Consequently, its primary diagnostic value is how it changes over time. In assessing whether changes over time reflect a change in the market's competitiveness, it is helpful to keep in mind the difficulty of precisely measuring prices and costs. One measure of this uncertainty is the 10% markup over costs that the market monitor for PJM uses to calculate mitigated bids for the PJM energy market.[13] Thus, year-to-year changes of less than 10%, such as those seen over the past several years, are not likely to reflect changes in the market's competitiveness. Given these modeling and estimation limits, the IMM determined that the recent QWLI results are consistent with competitive market outcomes. A comparison of the relationship between the price of natural gas (the dominant marginal fuel) and electricity prices further supports this conclusion. The correlation between natural gas and on-peak real-time energy prices (Hub LMPs) is approximately 0.94; the variance in natural gas prices explains about 90% of the variance in on-peak real-time Hub LMPs.

[13] PJM stands for PJM Interconnection LLC, the RTO for all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and the District of Columbia.

Table 1-1
Quantity-Weighted Lerner Index, %[(a)]

2004	2005	2006	2007	2008	2009	2010
−6	1	1	2	−1	5	6

(a) The QWLI = [(annual market cost based on market prices − annual market cost based on marginal cost estimates)/annual market cost based on market prices].

Figure 1-2 shows average actual and fuel-adjusted real-time electric energy prices for 2000 to 2010. The fuel-adjusted electric energy price is a metric developed by the IMM to estimate the impact that input fuel prices have on electric energy prices. After adjusting for changes in fuel prices, average energy prices have remained stable since 2000.

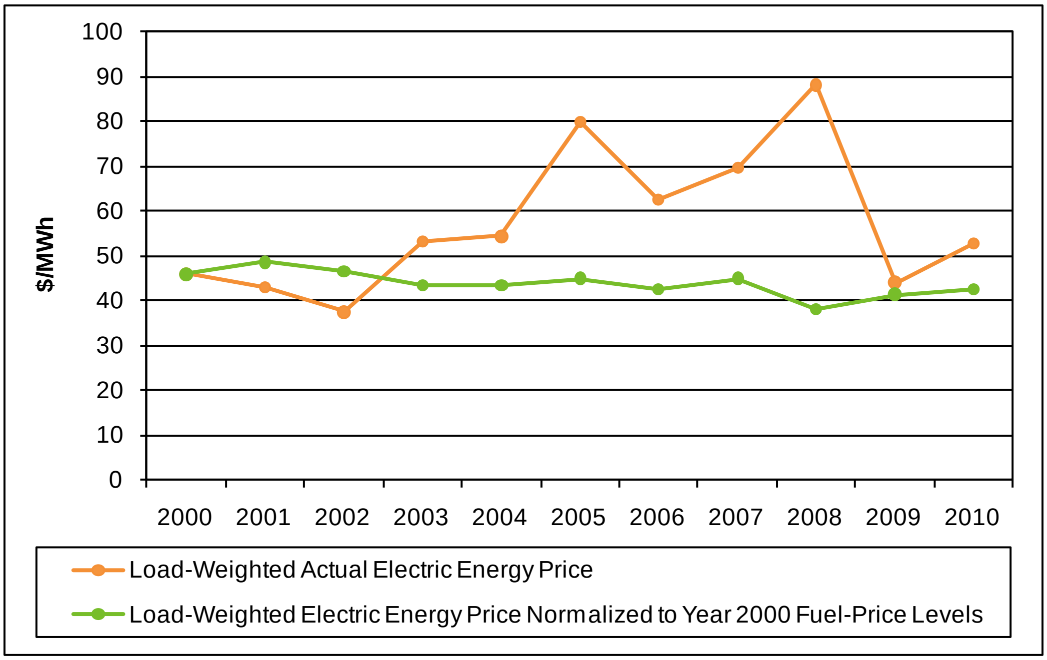

Figure 1-2: Actual and fuel-adjusted average real-time electric energy prices, 2000 to 2010.

Note: The prices are average Hub prices weighted by system load.

1.3 Market Results and Findings

The key results and findings for the energy and reserve markets in 2010 show an overall increase in energy prices and congestion costs and a continued increase across the year in the frequency and magnitude of nonzero real-time reserve prices. The IMM continues to observe a shift in the relationship between day-ahead and real-time prices in 2010, with day-ahead prices switching from prices that were higher than real-time prices, on average, to prices that were lower than real-time prices, on average. As described below, these market outcomes are consistent with observed changes in several key inputs, in particular, higher fuel prices; the extended, unexpected outage of a large resource from May to December; warmer summer weather; lower levels of hydroelectric production; and a reduced need to operate generation for local second-contingency protection.

1.3.1 Annual All-In Wholesale Electricity Cost

Figure 1-3 shows the average annual all-in wholesale electricity cost metric and natural gas prices for 2008 through 2010. The all-in cost includes the cost of electric energy, forward reserves, regulation, capacity, daily reliability commitments, and FERC-approved Reliability Cost-of-Service Agreements (Reliability Agreements).[14] The all-in cost of wholesale electric energy increased from $59.30/MWh in 2009 to $65.60/MWh in 2010, a 10% increase.

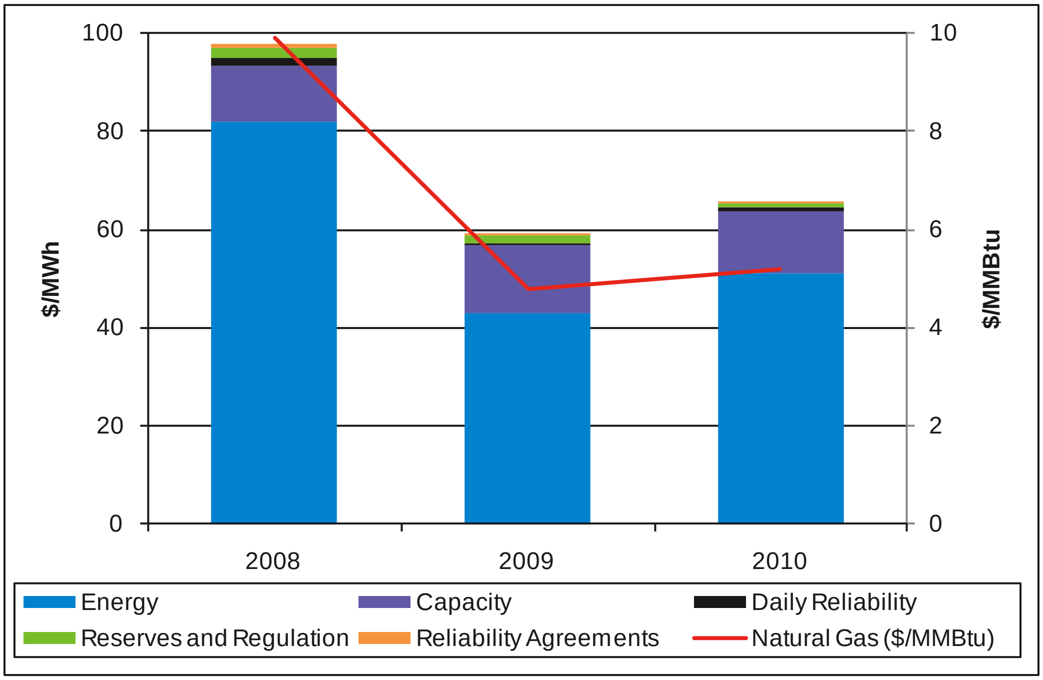

Figure 1-3: All-in cost for electricity.

Notes: The daily reliability and Reliability Agreement costs are allocated systemwide to enable a systemwide rate to be calculated. These costs actually are allocated to the load zone in which they occur. MMBtu stands for *millions of British thermal units*, a measure of the amount of heat energy in natural gas.

Source: Natural gas price information provided by the Intercontinental Exchange, Inc. (ICE), http://www.theice.com.

The energy component increased by 19%, from $42.89/MWh in 2009 to $50.98/MWh in 2010, as a result of higher fuel prices and increased loads. Daily reliability costs, caused in part by the outage of a large unit in the second half of the year, rose from $0.44/MWh in 2009 to $0.73/MWh in 2010, a 67% increase. The capacity component decreased by 9% because the number of megawatts receiving capacity payments declined with the start of the Forward Capacity Market. The reserves and regulation component decreased by 19%, and the component for Reliability Agreements, which no longer applied after May 31, decreased 87%.

1.3.2 Energy Market and Real-Time Reserve Pricing

This section provides the key results and findings for the energy markets in 2010 and comparisons to data from previous years.

[14] Reliability Agreements no longer applied after May 31, 2010, when the FCM transition period ended.

1.3.2.1 Electric Energy Prices

The average day-ahead and real-time electric energy prices at the New England Hub in 2010 were $48.89/MWh and $49.56/MWh, respectively. Table 1-2 shows average annual and quarterly day-ahead and real-time Hub prices for 2010. Average annual day-ahead prices in 2010 were 1.4% less than average annual real-time prices.

Table 1-2
2010 Day-Ahead and Real-Time Hub Prices ($/MWh)

	Annual	Q1	Q2	Q3	Q4
Day ahead	$48.89	$50.45	$43.27	$53.33	$48.49
Real time	$49.56	$51.71	$45.55	$54.26	$46.70
Difference	−$0.67	−$1.26	−$2.28	−$0.93	$1.79

In 2005, annual day-ahead prices were 2.4% greater than annual real-time prices on average. In mid-2009, the quarterly average day-ahead price became less than the quarterly average real-time price, and the annual average difference was negative as well. This trend continued through the third quarter of 2010, as shown in the table.

Compared with 2009, prices for all major fuel types were higher in 2010. Natural gas prices increased by 9%; residual fuel oil prices, 29%; distillate fuel oil prices, 30%; and coal prices, 27%. Figure 1-4 shows fuel prices and Hub indices normalized to January 2009. In the summer of 2010, natural gas prices fell more steeply than real-time LMPs because of two main factors. First, oil units were dispatched and set prices more frequently, especially during the peak load hours during the summer; and second, the frequency and magnitude of real-time reserve prices increased, which increased the real-time LMP. See Section 3.1.2.2 for additional analysis.

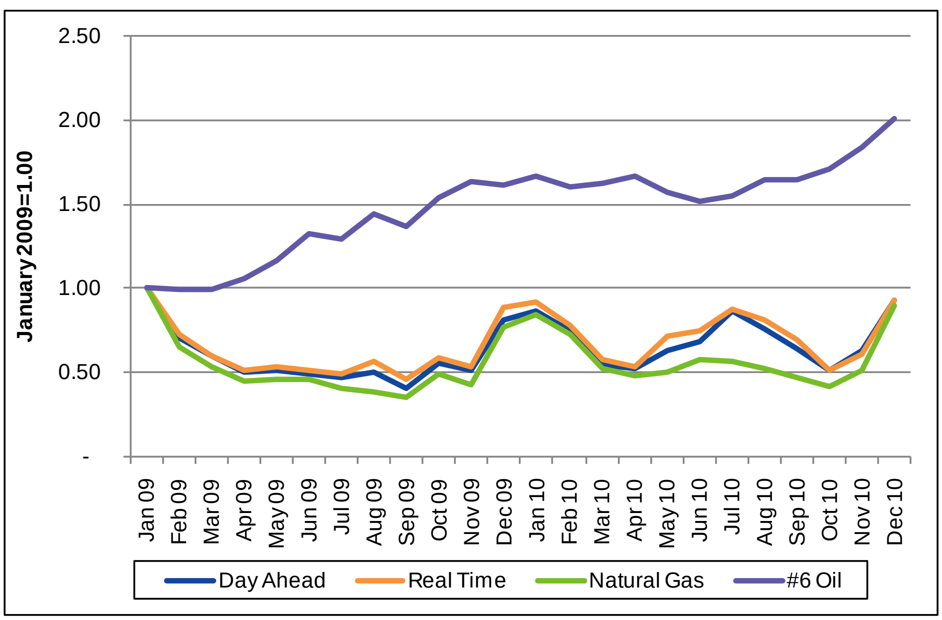

Figure 1-4: Monthly fuel prices for natural gas and #6 oil and day-ahead and real-time Hub indices, 2009 to 2010, compared with January 2009.

Source: Natural gas price information provided by the Intercontinental Exchange, Inc. (ICE); http://www.theice.com.

Weather-normalized net energy for load in 2010 was 1.3% higher than in 2009.[15] The 2010 summer peak was 8% higher than in 2009; 0.5% lower, weather normalized. Table 1-3 summarizes actual and weather-normalized loads for 2008 through 2010.

Table 1-3
Annual and Peak Electric Energy Statistics, 2008 to 2010

	2008	2009	2010	% Change 2009 to 2010
Annual NEL (GWh)[(a)]	131,754	126,839	130,771	3.1%
Normalized NEL (GWh)	131,215	128,268	129,910	1.3%
Recorded peak demand (MW)	26,111	25,100	27,102	8.0%
Normalized peak demand (MW)	27,525	27,220	27,075	−0.5%

(a) Net energy for load is calculated as total generation (not including the generation used to support pumping at pumped-storage hydro generators), plus net imports.

On the supply side, hydroelectric production was down, and fossil-fuel-fired generation production was generally up. Yearly hydroelectric production in 2010 was significantly lower compared with the record and near-record highs of the past two years (20% lower than 2008 and 17% lower than 2009) and only 8% over the historical average hydro production from 2000 to 2007.[16] Over the course of the year, hydroelectric resources produced 6% of total system generation as a percentage of NEL, down from 7% in 2009.

1.3.2.2 Real-Time Reserve Prices

In real time, the dispatch of resources to meet the energy and reserve requirements is jointly optimized. In the presence of a binding reserve constraint, the real-time reserve price is equal to the opportunity cost of the resource not dispatched for energy, but rather held to satisfy the reserve requirement, capped by the Reserve Constraint Penalty Factor (RCPF).[17] Since the second quarter of 2009, the surplus of on-line capacity has decreased because the ISO has not needed to commit as many megawatts to satisfy local reliability needs. This reduction in surplus means that the system is operating more tightly, leading to an increase in both the percentage of intervals in which reserves had a positive price and the level of those prices. As expected, this reduction in the availability of reserves from surplus on-line resources continued into 2010, as shown in Table 1-4, which shows the average price during the intervals in which the constraints were binding.

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[15] *Weather-normalized* results are those that would have been observed if weather were the same as the long-term average.

[16] Percentages are based on annual historical generation data reported by the ISO at "Energy Sources in New England, 2010" (http://www.iso-ne.com/nwsiss/grid_mkts/enrgy_srcs/index-p1.html) and subsequent web pages. Refer to Section 8.1 for additional information.

[17] *Reserve Constraint Penalty Factors* are administratively set limits on redispatch costs the system will incur to meet reserve constraints. Each type of reserve constraint has a corresponding RCPF.

Table 1-4
Average TMSR Price for Intervals with Nonzero Prices by Quarter, 2009 to 2010

	Q1	Q2	Q3	Q4
2009 average TMSR price for intervals with nonzero prices[(a)]	\$23.74	\$15.65	\$21.11	\$42.76
2010 average TMSR price for intervals with nonzero prices[(a)]	\$57.06	\$38.08	\$47.57	\$14.89

(a) Ten-minute spinning reserve (TMSR), also called 10-minute nonsynchronized reserve, is reserve capability offered by on-line generating units able to increase output within 10 minutes in response to a contingency.

The supply of 10- and 30-minute reserve capability was further reduced in the second half of 2010 by the outage of one the region's large flexible generators, which did not come back on line until December. Lower reserve prices in the fourth quarter were the result of the return of the generator and additional on-line capacity created by a requirement, imposed by the North American Electric Reliability Corporation (NERC) in response to the September 2 event, to carry 112% (rather than 100%) of the system's largest first-contingency loss as 10-minute reserve through the end of the year.

1.3.2.3 Congestion Revenue and Financial Transmission Rights

In 2010, revenue from the Financial Transmission Rights (FTRs) auction fell below realized congestion revenue, as shown in Table 1-5.[18] The congestion fund represented 0.6% of the energy market value in 2010. The increase in the value of the congestion fund compared with 2009 was caused by increased fuel prices and an increase in the amount of congestion on the system because of the facility outage mentioned above as well as higher system loads.

Table 1-5
Summary of Day-Ahead Congestion Revenue and Auction Revenue

	Day-Ahead Congestion Revenue (Millions \$)	Total Auction Revenue (Millions \$)	Auction Revenue as % of Day-Ahead Congestion Revenue
2008	125.4	116.7	93%
2009	26.7	71.1	266%
2010	37.3	30.2	81%

[18] *Financial Transmission Rights* allow participants to hedge against the economic impacts associated with transmission congestion and provide a financial instrument to arbitrage differences between expected and actual day-ahead congestion.

1.3.2.4 Virtual Transactions

Over the past year, the volume of submitted and cleared virtual supply offers has decreased and the volume of virtual demand bids has stayed relatively flat, despite real-time prices exceeding day-ahead prices on average for the year. Overall, the IMM has noted that a number of participants have reduced their volume of virtual trading activity or have changed their bidding strategies. The volume of virtual supply offers recovered somewhat in the fourth quarter 2010, the result of a positive day-ahead premium overall in the quarter.

This behavior is broadly consistent with the following:

- Through the third quarter 2010, changes in the day-ahead/real-time price relationship to one in which average real-time prices were higher than average day-ahead market prices (see Section 1.3.2.1) have reduced the opportunities for virtual supply in the day-ahead market. To some extent, this has turned around in the fourth quarter 2010.
- The risk associated with taking virtual positions has increased, given, to some extent, the increased volatility of real-time prices and the magnitude and uncertainty of real-time NCPC.
- The transaction costs associated with taking virtual positions are high and uncertain. Over the past year, the total allocated NCPC charges have exceeded the total gross profits from the virtual positions.

Those virtual traders who have remained in the market have added estimates of the per-megawatt-hour allocation of NCPC to their bids and offers. The resulting price spread of several dollars per megawatt-hour effectively limits day-ahead and real-time price convergence (i.e., less supply and demand economically clear the day-ahead market).

During the year, the profitability of virtual positions totaled $14 million. The total allocation of real-time NCPC charges to these positions totaled $22.2 million. Net of real-time transaction costs associated with NCPC, virtual positions realized a total loss of $8.1 million. The imposition of this disproportionately high level of transaction costs may threaten the viability of virtual transactions in the Day-Ahead Energy Market, with serious implications for the performance of the market. The IMM has recommended that the ISO consider revising the market rules so that real-time NCPC charges are not allocated to virtual transactions. The ISO presently is evaluating this recommendation. Refer to Section 3.3.3 for additional discussion and analysis.

1.3.2.5 Demand Resources

Table 1-6 shows program enrollments for demand response and *other demand resources* (ODRs), by month, for the pre-and post-FCM periods in 2010.[19] The number of megawatts of demand resources participating in ISO markets decreased when the new programs went into effect on June 1, 2010.

[19] *Demand response* refers to the reduction in the consumption of electric energy from the network by market participants in exchange for compensation based on wholesale market prices. *Other demand resources* are demand-side resources, such as energy efficiency, load management, and distributed generation at a retail customer's site, that are outside the ISO's control but that reduce demand by at least 100 kW; participate as capacity resources in the New England Balancing Authority Area; and are subject to ISO measurement, verification, and review procedures to demonstrate their total amount of demand reduction.

Table 1-6
Demand-Response Program Enrollments, Pre-FCM and Post-FCM (MW)

Pre-FCM[a]	**Real-Time Price Response (RTPR) Resource**	**30-Min. Real-Time Demand Response (RTDR)**	**2-Hr Real-Time Demand Response w/ Gen.**	**Profiled Demand-Response Resource**	**Other Demand Resources**	**Total Demand-Resource Enrollments**
	65	1,999	217	17	554	2,852
Post-FCM[b]	**Real-Time Demand-Response (RTDR) Resource**	**Real-Time Emergency Generation Resource (RTEG)[c]**	**On-Peak Demand Resource**	**Seasonal-Peak Demand Resource**		**Total Demand-Resource Enrollments**
	826	645	499	146		2,116

(a) Pre-FCM numbers are May 2010 enrollments.

(b) Post-FCM numbers are June 2010 enrollments.

(c) *Real-time emergency generation* is distributed generation the ISO calls on to operate during a 5% voltage reduction requiring more than 10 minutes to implement (i.e., OP 4 Action 6) or more severe actions but must limit its operation to 600 MW to comply with the generation's federal, state, or local air quality permit(s), or combination of permits, as well as the ISO's market rules. RTEG operations result in curtailing load on the grid as the distributed energy provided by the emergency generator begins serving demand. Real-time emergency generators must be available from 7:00 a.m.to 7:00 p.m. Monday through Friday on nonholidays, they must begin operating within 30 minutes of receiving a dispatch instruction, and they must continue operating until receiving an ISO instruction to shut down.

The apparent drop in resource capability from the transition period to the FCM does not indicate that demand-resource participation in the region dropped but that methods have improved for measuring demand reductions and the performance requirements under the FCM compared with the transition period.[20] For example, under the transition period, reductions were measured as the largest reduction during a five-minute dispatch interval. Under the FCM, reductions are measured over an hour. In an apparent response to FCM's performance requirements, demand-resource providers have aggregated more customers to support a given capacity supply obligation (CSO) than they did under the transition period.

Table 1-7 shows total payments to demand-response resources for 2010. Resources receiving capacity payments include reliability programs and ODRs in the pre-FCM period and RTDR, RTEG, and on-peak and seasonal-peak resources in the FCM period.

[20] The period between December 2006, when the FCM Settlement Agreement terminated the Installed Capacity Market, and June 1, 2010, when the winners of the first FCA needed to deliver capacity, is referred to as the FCM transition period. For background information on the settlement, see Devon Power LLC, et al., *Explanatory Statement in Support of Settlement Agreement of the Settling Parties and Request for Expedited Consideration and Settlement Agreement Resolving All Issues*, FERC filing, Docket Nos. ER03-563-000, -030, -055 (March 6, 2006, as amended March 7, 2006).

Table 1-7
Total Payments to Demand-Response Resources, 2010

Period	Day-Ahead Load-Response Program Payments	Real-Time Price Response Payments	Capacity Payments	Total
Jan to May	$515,497	$278,571	$74,251,383	$75,045,451
Jun to Dec	$7,865,707	$625,518	$55,437,070	$63,928,295

Demand Resource Performance on June 24—On June 24, 2010, demand resources with a capacity supply obligation were required to perform for the first time in response to real-time dispatch instructions. From 1:48 p.m. until 4:24 p.m., the ISO dispatched 669 MW of demand response. By 4:24 p.m., loads had decreased enough to permit the reduction of dispatched demand response from 669 MW to 300 MW. The control room operators stopped dispatching demand response at 4:57 p.m. In aggregate, demand-response performance was good, providing 653 MW of estimated reductions. However, performance of individual resources varied significantly from their CSOs. Figure 1-5 is a histogram of demand-resource performance as a percentage of CSO megawatts (10% interval bins).

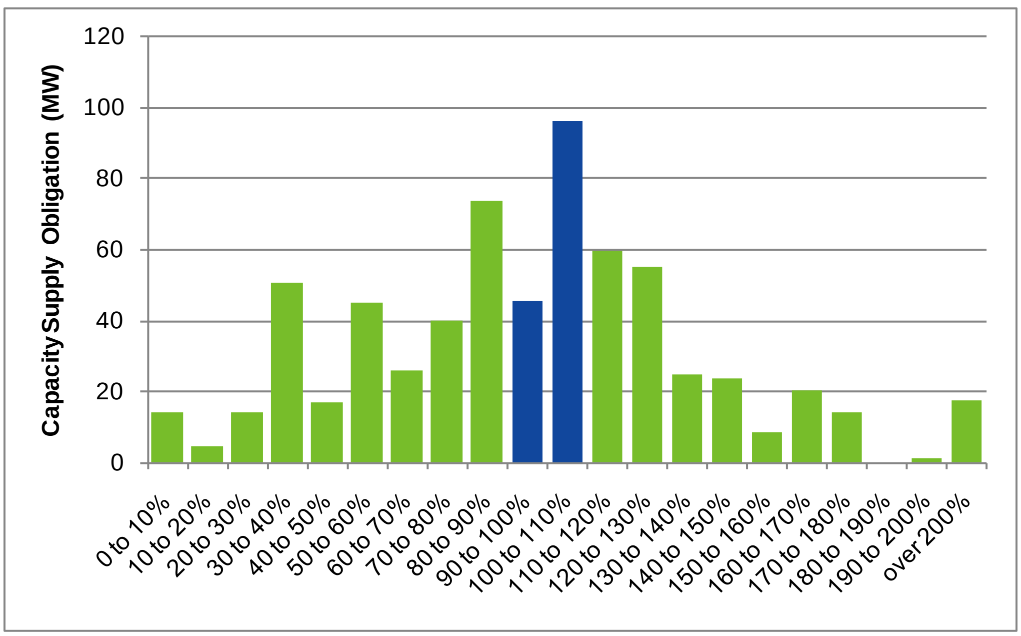

Figure 1-5: Histogram of demand-resource dispatch performance at 100% dispatch compared with capacity supply obligation; demand-resource reduction as a percentage of CSO during the June 24, 2010, OP 4 event.

Notes: The blue bars denote the resources that performed in the 90 to 110% range for generation dispatch of CSO. OP 4 refers to ISO New England Operating Procedure No. 4, *Action during a Capacity Deficiency* (April 29, 2010), http://www.iso-ne.com/rules_proceds/operating/isone/op4/OP4_RTO_FIN.doc.

For the June 24 event, resources that performed within the 90 to 110% threshold for generator dispatch of CSO totaled 141 MW, or 22% of the total demand-resource CSO of 653 MW.[21] This

[21] Section 7.5.4 explains the selection of the 90 to 100% threshold.

means that 78% of resources performed at a level more than 10% different from their capacity supply obligation. This discrepancy appears to be the result of several factors:

- A desire or need by some demand-response providers to use the event to audit new assets
- The FCM provisions that allow overperforming demand-response resources to receive an allocation of the penalties paid by underperforming resources

This analysis, as well as ISO settlement of demand resources, has been complicated and delayed because of problems with the data needed to calculate resource performance and settlements submitted by some demand resources. As described further in Section 3.6, up to 10% of demand resource data provided in any given month has had significant problems. The ISO has imposed data-validation requirements on demand resources and is working with demand-resource providers to improve data quality. The IMM will continue to monitor the performance of demand resources and may recommend design changes in the future.

Day-Ahead Load-Response and Price-Response Programs—As described in Section 2.7, the Day-Ahead Load-Response Program pays participants that commit to reducing their load in the day-ahead market for reducing their load in real time. The real-time reductions are measured by comparing actual consumption to baseline consumption, which estimates what the load would have consumed absent the interruption. After reviewing the program, the IMM recommends revising two aspects to increase the likelihood that participants are paid for actual load reductions, as the program rules require, rather than apparent load reductions. These aspects are the program's minimum offer level and the calculation of the resource's baseline consumption.

The program rules permit minimum offers of 100 kW, and most offers are made at the minimum offer level of 100 kW. Under the current rules, a participant with an accepted offer and load less than the baseline is paid the entire difference between its actual load and its baseline. A participant with an accepted offer and load greater than the baseline must purchase only 100 kW in the real-time market. This enables participants to benefit from errors in the baseline measurement that result in apparent reductions while taking on only the risk of purchasing 100 kW in the real-time market rather than the day-ahead market. The IMM recommends that participants be paid only for reductions in their asset's consumption offered into the day-ahead market as part of the DALRP. For example, a participant that wants to commit to reducing its load by 1 MW below its baseline must offer the full 1 MW into the DALRP. The participant must then ensure that its consumption is 1 MW below its baseline in real time; if not, it will be exposed to purchasing back the full 1 MW in real time.

The current demand-response baseline calculations have several characteristics that may result in DALRP and the price-response-program payments to load assets that take no action to reduce load, contrary to the program rules and intent. First, baselines do not include data from days when an asset clears in the DALRP or participates in a real-time price-response or reliability event. When an asset clears in the DALRP on sequential days, its baseline is carried forward from the period before it cleared. If this baseline is higher than the asset's current consumption, it can receive payments in the DALRP without taking action to reduce load. To prevent the "freezing" of baselines, the IMM recommends adopting an improved process for establishing initial baselines and developing a more robust and accurate baseline methodology.

Second, the current rules include baseline adjustments that may inappropriately increase baselines. Specifically, baselines are adjusted each day on the basis of the load from 7:30 a.m. to 9:30 a.m. to correct for load levels on a given day. However, this adjustment is made only in an upward direction. Also, baselines are not adjusted during event days because, by definition, load is being reduced on event days. While these adjustments were put in place to account for valid business practices at demand-response asset sites, they should be reviewed to ensure that they do not provide opportunities for the exercise of strategic behavior. In addition, the IMM's analysis has shown that a large portion of the DALRP payments are made to distributed generation resources. The IMM recommends a review of their baseline adjustment rules.

More broadly, the IMM is skeptical of the long-term viability of measuring the performance of demand-response programs using baselines to estimate how much energy a participant would have consumed. However, FERC Order 745 that addresses demand response will require the ISO to develop baselines to implement FERC's rulemaking for price-responsive demand.[22] To ensure that payments in the DALRP are made, consistent with the rules, only to participants that have taken action to reduce loads, these baselines should minimize the likelihood of paying for apparent, rather than real, reductions. To the extent possible, the ISO should use actual consumption as close to the time of reduction as possible. Using an estimated baseline may be necessary, however, for reductions committed the day before or several hours before real time. These estimated baselines should reflect the recommendations detailed above.

1.3.3 Reliability and Operations

Table 1-8 summarizes the Net Commitment-Period Compensation payments to generators for local second-contingency protection resources (LSCPRs), distribution, and voltage and economic NCPC. It shows the continuation through 2010 of the trend that began in the second half of 2009, away from commitments by ISO operations to satisfy local reliability needs to commitments by the ISO to meet capacity needs. Economic NCPC, which is incurred largely as a consequence of the energy market's three-part bidding structure, was 0.99% of the total generator compensation.[23]

Table 1-8
Total Daily Reliability Payments, 2009 and 2010 (Million $)

Payment Type	2009	2010	Difference	% Change
Economic and first-contingency payments	32,556,784	84,683,101	52,126,317	160%
Second-contingency reliability payments	17,527,919	3,942,538	−13,585,381	−78%
Distribution	586,034	1,635,375	1,049,341	179%
Voltage	5,006,698	5,200,483	193,785	4%
Total	55,677,435	95,461,497	39,784,063	71%

A major factor for the increase in economic NCPC payments in 2010 was the commitment of high-cost oil-fired generators to meet load and reserve requirements over the peak hour. Because of their high costs, these resources sat at economic minimum (ecomin) for most hours of the day and were

[22] *Demand-Response Compensation in Organized Wholesale Energy Markets*, 18 CFR § 35 (March 15, 2011), http://www.iso-ne.com/regulatory/ferc/orders/2011/mar/rm10-17-000_3-15-000_demand_resp_order.pdf.

[23] Generating resources submit three-part bids that reflect the cost of start up, no-load operation, and incremental energy production. The price received by the marginal resource equals its incremental energy offer. At this price, the resource earns no contribution against its start up and no-load costs. The generating resource is made whole for such shortfalls accumulated across the operating day through the payment of economic NCPC.

dispatched above their minimum operating levels only over the peak hours of the day.[24] Consequently, the total cost of running these units exceeded the total revenues they collected through the energy market, with the difference paid as economic NCPC. As discussed further in Section 7.1, most of the economic NCPC occurred in the second half of 2010 after the outage of the large resource mentioned above.

The need to commit generators out of market (OOM) to maintain system reliability and to compensate them with NCPC has been a long-standing issue in New England. While the sum of all NCPC payments is only 1.12% of total compensation to generators, the energy produced by resources operating out of market lowers the energy price and thereby prevents the energy price from accurately representing the cost of serving load. The IMM has reviewed the ISO's commitments that have caused much of the economic NCPC and has determined that the resources generally were needed to meet reliability needs. This can be seen in Figure 1-6, which shows that very few megawatts committed by the ISO were operating at economic minimum during the hours for which they were committed. A large number of megawatts operating at economic minimum would suggest that the ISO has scheduled more resources than necessary to meet actual load plus reserves.

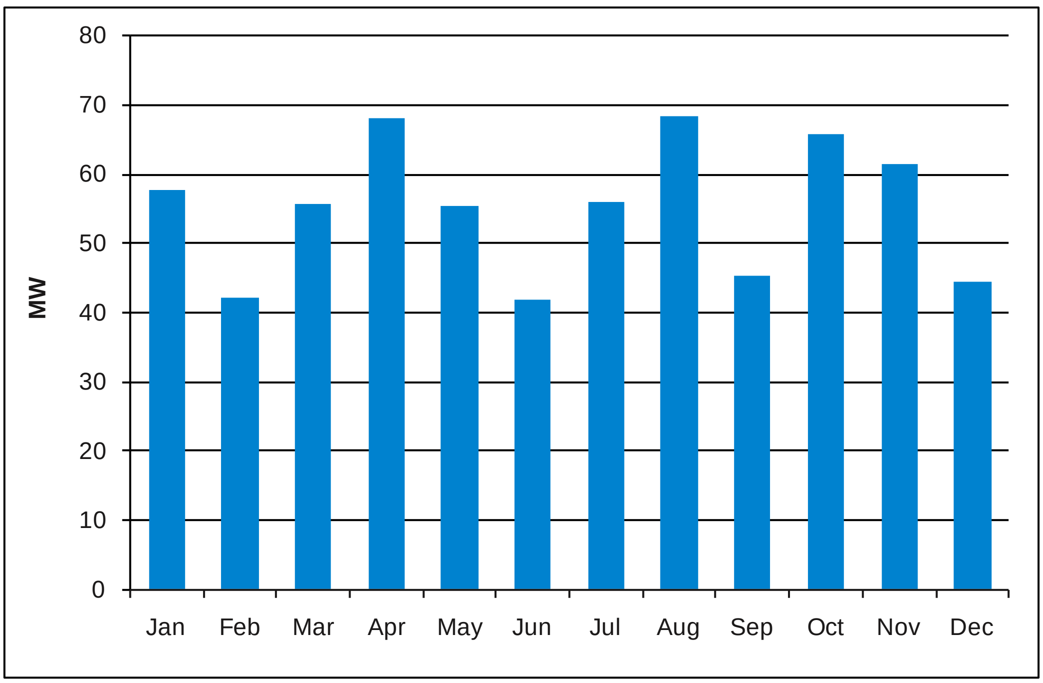

Figure 1-6: Average generation scheduled after day-ahead market closes and operated at economic minimum, 2010 (MW-month).

Economic NCPC is likely to remain high as long as high-cost, inflexible resources are used to meet system operating capacity needs. If these resources were replaced by more flexible resources, economic NCPC would likely decrease. Currently, the region has approximately 6,000 MW of oil or

[24] *Ecomin* is the minimum amount of electric energy (in megawatts) available from a generating resource for economic dispatch.

oil/gas steam units.[25] These former baseload or intermediate-load units operate very few hours per year in the energy market and receive most of their revenues from the capacity market. The floor price in the capacity market may be contributing to these resources' remaining in operation even though they are not earning revenue in the energy market.

1.3.4 Supplemental Capacity Commitments

After the Day-Ahead Energy Market clears each day, the ISO performs a Reserve Adequacy Analysis (RAA) and, if necessary, commits generators to meet capacity and reserve requirements. The RAA commits generators whenever insufficient capacity clears in the day-ahead market to meet the ISO load forecast plus operating reserve requirement.

The amount of capacity on line affects LMPs and NCPC costs. If too much capacity is on line, LMPs are likely to be artificially low and NCPC costs high. If too little capacity is on line, reliable operation may be compromised and prices artificially high. To measure the difference between the actual amount of capacity on line compared with what is needed, the IMM analyzes the operating plan created by the RAA at 10:00 p.m. each day. This analysis measures the difference between the sum of total supply available (aggregate economic maximum of all on-line units plus net imports) minus system needs (load plus 10-minute spinning reserve) for each hour.[26] Positive differences are termed surplus, and negative differences, deficiencies. The IMM has chosen to exclude 10-minute nonspinning reserve (TMNSR) and 30-minute operating reserve (TMOR) from this analysis because the ISO seldom commits resources to meet these requirements and any surplus off-line 10- and 30-minute reserve will distort the assessment of whether ISO commitments result in surplus capacity.[27]

Surplus can arise from generation that clears in the Day-Ahead Energy Market (e.g., if the load clearing in the day-ahead market exceeds the real-time load), self-schedules, or the supplemental commitment performed in the RAA. Thus, the surplus is created both by the market as well as commitments the ISO makes for reliability. This analysis quantifies surplus resulting from ISO commitments and market decisions.

The IMM analyzed surplus capacity for 2008 to 2010. Table 1-9 summarizes the results for peak hours, which are important because the RAA commitment decisions are based on meeting needs for the peak hour.[28]

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[25] The data come from the ISO's 2010 *Capacity, Energy, Load, and Tansmission (CELT) Report* (May 18, 2010)**.** More detailed information about generating capacity is available in the ISO's CELT reports, http://www.iso-ne.com/trans/celt/report/index.html.

[26] *Economic maximum* (ecomax) is the highest unrestricted level of electric energy (in megawatts) a generating resource is able to produce, representing the highest megawatt output available from the resource for economic dispatch.

[27] *Ten-minute nonspinning reserve* is operating reserve provided by off-line generation that can be electrically synchronized to the system and increase output within 10 minutes in response to a contingency; also called 10-minute nonsynchronized reserve. *Thirty-minute operating reserve* is operating reserve provided by on-line or off-line operating-reserve generation that can either increase output within 30 minutes or be electrically synchronized to the system and increase output within 30 minutes in response to a contingency.

[28] These are the results of the operating plan as of 10:00 p.m. The results do not include response to real-time events, such as load forecast error.

Table 1-9
Average Hourly Surplus, Peak Hours, 2008 to 2010

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
2008	754	429	494	555	776	676	704	863	908	670	421	668	661
2009	647	426	507	486	324	425	310	460	316	151	235	226	374
2010	158	131	199	230	119	270	461	360	322	305	336	199	259

The average surplus for on-peak hours has dropped from 661 MW in 2008 to 259 MW in 2010. This has been largely driven by improvements in the transmission system and the resulting decline in the need to commit resources for local reliability reasons, as discussed above. Table 1-9 also shows that the surplus in 2010 was highest in the peak summer season.

The analysis also found that the need to meet the instantaneous peak within the peak hour contributes approximately 130 MW to the surplus when measured over the integrated hour. During peak hours, the surplus generally is the result of ISO commitment decisions, while during off-peak hours, the results of the day-ahead market and participant decisions to self-schedule resources drive the surplus amount. The analysis is more fully described in Section 7.2.

1.3.5 Market Performance on September 2, 2010

On September 2, 2010, at 1:09 p.m., a large resource tripped. Many generators were called on or had their desired dispatch point (DDP) increased to restore system frequency, return transmission interfaces to within limits, and restore area control error and operating reserves in accordance with established criteria. The ISO was unable to return the ACE to its predisturbance value within 15 minutes, taking 23 minutes to accomplish this task. According to a review by ISO System Operations, inadequate generator response to ISO electronic dispatch instructions was an important contributing factor to the inability of the ISO to restore ACE within the 15-minute time requirement. The IMM analyzed market pricing, generator performance, and the performance of the dispatch software to better understand why the ISO took longer than 15 minutes to return the ACE to predisturbance levels.

The IMM's review examined generator response to the contingency-dispatch instructions issued by the ISO approximately two minutes after the trip of the resource. This set of dispatch instructions was intended to return the system ACE to predisturbance levels. This review found the following:

- There was no evidence that any generator withheld capacity during this time period.
- Generator response to the dispatch instructions was mixed. One-hundred forty-seven generators were dispatched for a total of 1,942 MW. The total generator response within 14 minutes of the disturbance was 1,209 MW (62%), 729 MW short of what was electronically or verbally dispatched, as follows:
    - Fifty-six generators were off line and given a dispatch order to start. A total of 936 MW of off-line resources was dispatched, and the total response was 673 MW (72%)—263 MW short of what was dispatched. The performance of off-line resources is consistent with past off-line unit performance.

- o Ninety-one generators were on line and given a dispatch order to ramp up. A total of 1,006 MW was dispatched, and the total response was 536 MW (53%)—470 MW short of what was dispatched. The response of on-line resources was poorer than expected.

- At the time of the unit trip, operating reserve was held in small amounts, spread across many units operating at the top of their range. Given the ambient air conditions and the operating range of the units, generators did not perform consistent with their offer data parameters, in particular, the unit ramp rates and economic maximum. Generator ramp rate and economic maximum parameters apparently did not reflect the precise capabilities of the units, given that day's temperature and humidity, and. ISO system operators would have possessed better information to dispatch the system had such parameters been more accurately reported to the ISO.
- The outage of the large flexible generator mentioned earlier made the return of the ACE to predisturbance levels more difficult.

The IMM reviewed pricing during the event. Until the ACE was returned to predisturbance levels, the LMPs appropriately included the $850/MWh penalty factor that reflects a shortage of 10-minute reserves. However, the shortage of 10-minute reserves continued for approximately 20 minutes longer and was not properly reflected in the LMPs. Section 7.5 discusses this issue in more detail and explains that the LMP calculator makes certain assumptions that may cause the pricing to be inaccurate under reserve-shortage conditions.

Under the current rules, demand resources (RTEG and RTDR) are not dispatched within the economic security-constrained dispatch software, and they do not qualify to provide reserves. Instead, they are dispatched as part of OP 4. If demand resources had been available as 10-minute reserves and dispatched as part of a security-constrained dispatch solution during the September 2 event, some demand resources may have been able to reduce load within 15 minutes and help return the ACE to predisturbance levels. This highlights a key difference between demand and supply resources under the current rules; supply resources are required to offer into the energy market each day, while demand resources are able to be dispatched only in OP 4 conditions. The IMM noted this difference in its FCM Report and recommended that demand resources also be enabled to participate in the energy market.[29]

The September 2 event also highlighted the ambiguity of the rules regarding the failure to follow dispatch instructions. Two sections of *Market Rule 1* refer to following dispatch instructions: Section III.1.7.20, "Information and Operating Requirements," and Section III.3.2.3(e), "NCPC Credits."[30] The first reference generally requires resources to follow dispatch instructions but does not include any definition for following dispatch instructions. The second reference requires resources to be within 10% of their dispatch instructions to be eligible to receive Net Commitment-Period Compensation and be considered in setting the LMP. The lack of a performance standard in the general requirement has resulted in the widely held belief that a resource operating within 10% of its

[29] ISO New England Inc., *Internal Market Monitoring Unit Review of the Forward Capacity Market Auction Results and Design Elements* (FCM Report), FERC filing, Docket No. ER09-1282-000 (June 5, 2009), 7, http://www.iso-ne.com/markets/mktmonmit/rpts/other/fcm_report_final.pdf.

[30] ISO tariff, *Market Rule 1*, Section III.1.7.20, "Information and Operating Requirements," and Section III.3.2.3(e), "NCPC Credits" (March 14, 2011), http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_sec_1-12.pdf.

dispatch instruction is following its dispatch instructions for all purposes. The IMM recommends that the ISO review the failure-to-follow rules, especially whether a different definition of following dispatch instructions is appropriate for purposes other than receiving NCPC payments and setting price.

1.3.6 Forward Capacity Market and Transition Period

This section summarizes the 2010 activities related to the Forward Capacity Market, including the FCM transition period payments, the results of the fourth FCA, and the reconfiguration auctions and bilateral transactions for the 2010/2011 capacity commitment period.

1.3.6.1 FCM Transition Period

FCM transition payments continued until the beginning of the 2010/2011 capacity commitment period on June 1, 2010, when the FCM payments based on the auction results began. FCM transition payment rates were $4.10/kW-month for January to May 2010, as specified by the FCM settlement. During 2010, FCM transition payments to qualifying capacity resources totaled $790.5 million.

1.3.6.2 Forward Capacity Auction

As of May 2011, the ISO has held four Forward Capacity Auctions, which have procured from 21 to 34% more than the capacity needed to meet the region's resource adequacy requirements, called the net Installed Capacity Requirement (NICR).[31] Table 1-10 shows the total capacity that qualified to participate in each auction, the total megawatts that cleared each auction, and the amount of capacity the auction was required to meet (the NICR). The table also shows the excess capacity that cleared above the NICR in each auction and the clearing prices. Because each FCA cleared capacity in excess of that necessary to meet the NICR, the floor price was reached in each auction. Total qualified capacity exceeded the NICR by 21% in FCA #1, by 32% in FCA #2, by 34% in FCA #3, and by 26% in FCA #4.

Table 1-10
Results of the First Four Forward Capacity Auctions

	FCA #1	FCA #2	FCA #3	FCA #4
Total qualified (MW)	39,165	42,777	42,746	40,412
Total cleared (MW)[(a)]	34,077	37,283	36,996	37,501
NICR (MW)	32,305	32,528	31,965	32,127
Excess cleared (MW)[(a)]	1,772	4,755	5,031	5,374
Clearing price ($/kW-month)	$4.50	$3.60	$2.95	$2.95

(a) This category excludes RTEG resources in excess of 600 MW.

[31] The *net Installed Capacity Requirement* values are the ICRs for the region, minus the tie-reliability benefits associated with the Hydro-Québec Phase I/II Interface (termed HQICCs). The HQICC is a monthly value that reflects the annual installed capacity benefits of the HQ Interconnection, as determined by the ISO using a standard methodology on file with FERC.

None of the auctions had import-constrained capacity zones; the ISO determined that each potential import-constrained area had sufficient existing capacity. Maine was modeled as an export-constrained capacity zone in all four of the auctions.

1.3.6.3 Out-of-Market and In-Market New Resources

Out-of-market resources, which participate in the FCM at prices below their costs, include certain new resources with offer prices less than 0.75 times the cost of new entry (CONE), new self-supplied resources, and capacity under ISO-issued requests for proposals (RFPs).[32] Figure 1-7 shows the new in-market and OOM capacity that cleared in the first four FCAs. In FCA #4, cleared OOM new entry accounted for 37% of cleared new capacity.

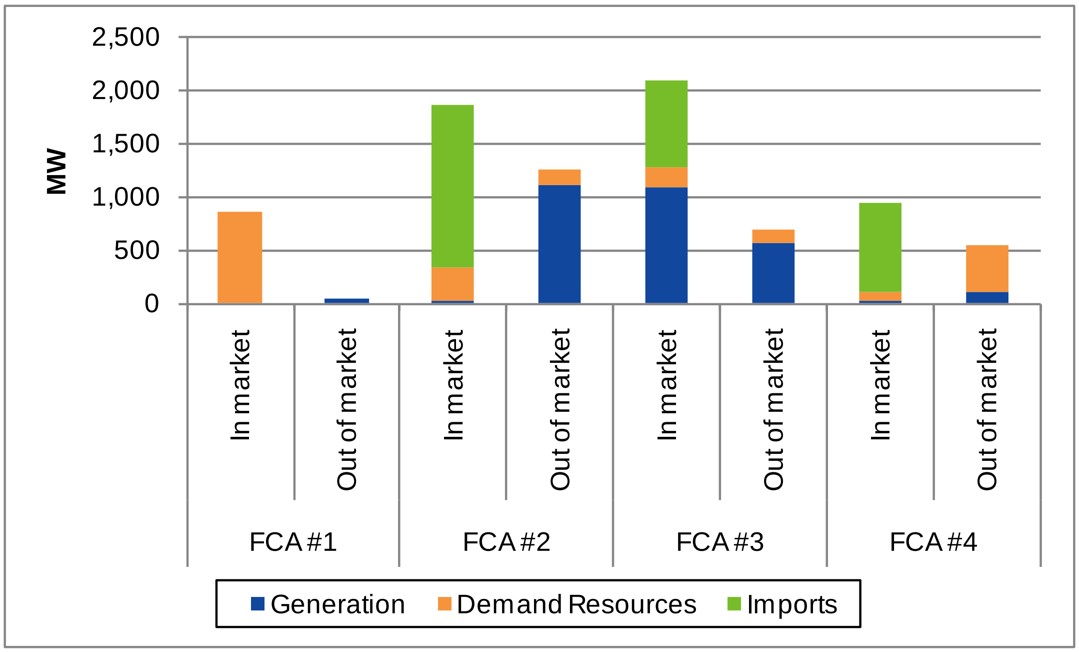

Figure 1-7: Cleared new, in-market, and out-of-market capacity, FCA #1, FCA #2, FCA #3, and FCA #4 (MW).

Figure 1-7 shows that, with the exception of FCA #3, most new in-market resources are either imports or demand resources. In FCA #3, the approximately 1,100 MW of in-market generation was not new generation but investment in an existing generating station. Thus, the Forward Capacity Market has not attracted new, in-market generation. Given current surpluses, the fact that new in-market generation has not entered the market is not a problem. However, with the looming possibility that some of the region's older resources retire and some of its nuclear units reach the end of their licenses, the ability of the market to attract timely new in-market generator entry remains largely untested.

[32] The CONE is used to (1) establish the starting price for each FCA, (2) set thresholds for reviewing delist bids to deter the exercise of market power, (3) set initial pricing for some reconfiguration auctions, and (4) determine pricing when the supply is inadequate and competition is insufficient. The CONE is derived from the capacity clearing price from previous FCAs, except for FCA #1, where it was administratively set.

1.3.6.4 Delisted Capacity Resources

Table 1-11 shows the accepted delist bids in FCA #4.[33] Existing generation accounted for the largest proportion of delisted capacity. However, demand resources are delisting at a greater rate than generating resources. Generator delists range up to 675 MW on a base of approximately 30,000 MW, or in the 2% range; demand-resource delisting ranges up to 489 MW on a base of about 2,500 MW, or nearly 20%. The ISO-approved 1,228 MW of delisted resources was nearly equaled by 1,190 MW of delist bids rejected for reliability reasons. Delist bids for Salem Harbor #3 and #4 (587 MW total) and the Vermont Yankee nuclear generating station (604 MW) were both rejected for reliability reasons. Most of the delist requests were dynamic bids submitted below 0.8 times the CONE; of the accepted delist requests in FCA #4, 26 MW were permanent, 100 MW were administrative, 535 MW were static and 567 MW were dynamic.

Table 1-11
Delisted Existing Resources by Type (MW)

Resource Type	FCA #1	FCA #2	FCA #3	FCA #4
Generation	622 (64%)	350 (39%)	543 (32%)	675 (55%)
Demand resources	296 (31%)	489 (55%)	257 (15%)	451 (38%)
Import	51 (5%)	51 (6%)	910 (53%)	102 (8%)
Total delisted	970	890	1,710	1,228

1.3.6.5 Reconfiguration Auctions and Bilateral Transactions, 2010/2011 Commitment Period

Participants can transfer and acquire capacity supply obligations through bilateral transactions and reconfiguration auctions.[34] Bilateral transactions and auction trades both can be for either one month or the entire one-year capacity commitment period, and volumes exchanged in monthly bilateral trades and the monthly reconfiguration auctions vary from month to month.

Table 1-12 shows capacity supply obligations transferred in the two annual reconfiguration auctions held for the 2010/2011 capacity period and bilateral trades for the period. A participant with a cleared demand bid transfers its CSO, while a participant with a cleared supply offer acquires an obligation. Cleared ISO supply offers represent an adjustment to system capacity requirements. The clearing price for the second annual reconfiguration auction was $1.50/kW-month, and the clearing price for

[33] An existing resource can submit a *delist bid* in an FCA to indicate that it wants to opt out of the auction before the deadline for qualifying existing capacity and does not want a capacity obligation below a certain price. *Static delist bids* are submitted for a resource before the auction and cannot be changed during the auction. *Permanent delist bids* prohibit resources from participating in any future auctions unless they qualify for and clear as a new resource in a subsequent FCA. As of the date of the permanent delisting, permanently delisted resources are prohibited from assuming any capacity obligation. *Dynamic delist bids* are submitted by participants during an auction. Unlike other types of delist bids, dynamic delist bids can be offered below 0.8 times the CONE threshold price, and the IMM does not review these bids in advance. Qualified new resources can leave the auction without delisting. *Export delist bids* are similar to static delist bids but may have an opportunity-cost component as part of the cost data. *Administrative export delist bids* are submitted for capacity exports associated with multiyear contracts and are initiated using the same requirements as for export delist bids. (See Section 2.2.3.1 for additional information on delist bids.)

[34] RTEGs cannot participate in reconfiguration auctions. RTEGs can only acquire CSOs from other RTEGs (not from any other resource types) in bilateral trades. Capacity imports can only acquire CSOs from other imports on the same path.

the third auction was $1.43/kW-month, well below the FCA #1 price of $4.50/kW-month.[35] A total of 960 MW was transferred in annual bilateral trades at an average price of $2.60/kW-month.

Table 1-12
Annual Reconfiguration Auctions and Bilateral Trades for 2010/2011 Capacity Period, Clearing Prices and Quantities

Auction	Annual Reconfiguration Auctions		Annual Bilateral Trades (June 1, 2010—May 31, 2011)	
	Demand Bids and Supply Offers Cleared (MW)	Clearing Price ($/kW-Month)	Trades (MW)	Average Trade Price ($/kW-Month)
Second ARA	198	$1.50		
Third ARA	444	$1.43	960	$2.60

Table 1-13 shows information about monthly reconfiguration auctions and bilateral transactions. Reconfiguration auctions have not yet taken place for all months in the capacity period. Auction clearing prices ranged from $0.76/kW-month to $2.25/kW-month. Monthly bilateral trade volumes have ranged from 81 MW (for the June 2010 commitment month) to 263 MW (for January 2011). Prices have ranged from $2.01/kW-month to $2.89/kW-month.

Table 1-13
Monthly Reconfiguration Auctions and Bilateral Transactions¸ Prices and Quantities

Obligation Month	Monthly Reconfiguration Auctions		Bilateral Transactions	
	Cleared CSOs (MW)	Auction Clearing Price ($/kW-Month)	Cleared CSOs (MW)	Average Trade Price ($/kW-Month)
Jun 10	75	$1.99	81	$2.57
Jul 10	58	$2.25	117	$2.59
Aug 10	95	$2.19	117	$2.89
Sep 10	86	$1.96	118	$2.83
Oct 10	140	$0.98	114	$2.01
Nov 10	227	$0.87	151	$2.01
Dec 10	179	$1.20	209	$2.55

1.3.7 Forward Reserve Market

Two Forward Reserve Market (FRM) auctions were conducted in 2010: in April, for summer 2010, and in August, for the winter 2010/2011 period.

[35] Only the second and third reconfiguration auctions were held for the 2010/2011 commitment period. A first auction was not scheduled.

1.3.7.1 Competitiveness of the Forward Reserve Market

Competition in the FRM has been heightened because of an increase in the number of participants and a drop in reserve requirements. These two factors resulted in a decrease in clearing prices in all reserve zones and an increase in offers of TMNSR, a higher-quality product. However, structural analysis of the FRM auctions still indicates a moderate to high concentration in the CT and SWCT reserve zones.

1.3.7.2 Locational Forward-Reserve Auction Results

The results of the locational forward-reserve auctions are shown in Table 1-14. Prices for New England systemwide 10-minute nonspinning reserve in both the summer and winter auctions declined from 2009 to 2010. Prices in the Connecticut and Southwest Connecticut reserve zones decreased from the $14.90/kW-month cap to $13.90/kW-month for summer 2010 and $6.02/kW-month for winter 2010/2011. These price decreases occurred because competition increased with a greater number of participants and reserve requirements dropped. Transmission improvements into the NEMA/Boston local reserve zone over the past few years have essentially rendered that area unconstrained. Absent a binding constraint in the auction, the local TMOR price is zero.

Table 1-14
Results of Locational Forward-Reserve Auctions ($/kW-Month)

Reserve Zone	Reserve Category	Summer 2009	Summer 2010	Winter 2009/2010	Winter 2010/2011
Systemwide	TMNSR	$6.30	$5.95	$6.08	$5.50
Systemwide	TMOR	$0	$5.95	$0	$5.50
SWCT	TMOR	$14.00	$13.90	$14.00	$6.02
CT	TMOR	$14.00	$13.90	$14.00	$6.02
NEMA/Boston	TMOR	$0	$0	$0	$0

1.3.8 Regulation Market

The Regulation Market provides moment-to-moment balancing services to ensure that generation and load are kept balanced in real time. This market functioned well in 2010. During the year, the ISO consistently exceeded the NERC reliability standards for this area and reduced the capacity on regulation.[36] As a result, the megawatts needed for regulation have decreased, and regulation prices have dropped.

The structure of the Regulation Market is evaluated using two metrics: HHI and RSI. The HHI for the New England Regulation Market is based on summer capabilities of regulation capacity to offer into the market. The maximum eligible regulation capability (MW) over all hours in the month for each lead participant's portfolio of resources was used in the HHI and RSI analyses. Throughout the year, the monthly HHI varied from a low of 751 to a high of 832, with an annual average of 790. The monthly RSIs exceeded 1,000 for every month in 2010. The results of the HHI and RSI analyses indicate that the Regulation Market is structurally competitive.

[36] NERC reliability standards can be accessed at http://www.nerc.com/page.php?cid=2|20 (NERC, 2011).

Payments to generators for providing regulation totaled $14.3 million in 2010, a decrease of $8.8 million from the 2009 cost of $23.1 million. The regulation requirement has fallen, reducing the regulation credit.

1.4 Mitigation and Market Reform Activities

This section summarizes IMM mitigation, market reform, and referral activities in 2010.

1.4.1 Mitigation and Market Reforms

According to *Market Rule 1*, Appendix A, the IMM has the authority and responsibility to mitigate electric energy offers under certain circumstances, as well as to apply rules that identify participant behavior that results in NCPC payments in excess of defined thresholds and virtual transactions that increase the hourly value of an FTR the participant holds.[37]

During 2010, no participant behavior required the application of Day-Ahead Energy Market mitigation. There were 10 Real-Time Energy Market mitigation events in 2010, 23 instances of day-ahead NCPC mitigation, and 28 events in which daily real-time NCPC payments paid to participants were mitigated retroactively. Three participants had their FTR revenues, associated with eight paths, reduced by a total of $11,649 pursuant to the FTR revenue-capping provisions of *Market Rule 1*.[38]

One market rule reform was implemented during 2010. On January 1, 2010, the local Reserve Constraint Penalty Factor was changed from $50/MWh to $250/MWh. This change is expected to provide more efficient real-time dispatch and pricing.

1.4.2 Behavior Requiring Referral to FERC

Market Rule 1, Appendix A, provides the IMM with a limited set of circumstances for applying mitigation activities without additional FERC involvement: energy market mitigation, NCPC mitigation, and FTR capping. When the IMM identifies other forms of potentially noncompetitive market participant behavior, *Market Rule 1* requires the IMM to refer the situation to FERC, which then investigates the conduct and applies penalties as warranted.

In 2010, the IMM made one nonpublic referral to FERC, bringing to six the total number of IMM referrals open before FERC. No referrals were closed in 2010.

1.5 Summary of IMM Recommendations

On the basis of observations of participant behavior and market outcomes in 2010 and the analysis presented herein, the IMM identified the following issues and makes the following recommendations for improving the market design. The issues and recommendations are listed in order of importance. Refer to the cross-referenced sections for further explanations of the identified issues.

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[37] ISO tariff, *Market Rule 1*, Appendix A, "Market Monitoring, Reporting, and Market Power Mitigation" (April 15, 2011), http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-a.pdf.

[38] *Market Rule 1*, Appendix A, Section III.A.8.4, "Cap on FTR Revenues" (April 15, 2011), http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

1.5.1 Issues

1. To ensure efficient and secure real-time operations, all resources must follow dispatch instructions. The Internal Market Monitor observed that on June 24, 2010, the majority of the dispatched demand-response resources either underperformed or overperformed. The performance discrepancies appear to be the result of several factors, including (1) possible incentive problems in the Day-Ahead Load-Response Program, (2) a desire or need by some demand-response providers to use the event to audit new assets, and (3) the FCM provisions that allow overperforming demand-response resources to receive an allocation of the penalties paid by underperforming resources. The IMM has not completed its analysis of all these factors, and the available data are limited at this time. The IMM will continue to monitor the performance of demand-response resources and may recommend design changes (see Section 7.4.4).

2. Currently, a shortage event begins after the 10-minute nonspinning reserve constraint has been violated for 30 contiguous minutes. By definition, in any interval in which the 10-minute nonspinning reserve constraint is violated, capacity is insufficient to meet the 10-minute requirement, even after redispatch, and there is no 30-minute operating reserve. On June 24, 2010, this condition occurred for one five-minute dispatch interval. The penalty structure in the FCM assumes that the performance of resources with CSOs will be evaluated when the system is tight. However, because it is extremely unusual for the system to be short of 10-minute reserves for half an hour, shortage events seldom occur. While the original FCM design defined shortage events as occurring only when the system was short of operating reserve, this definition may be too restrictive and may not meet the intent of the overall FCM performance penalty structure. The IMM will conduct additional analysis of the role of this feature in the FCM design and may recommend design changes (see Section 7.4).

1.5.2 Recommendations

1. The IMM recommends that the ISO revise the market rules so that real-time Net Commitment-Period Compensation charges are not allocated to virtual transactions. At the same time, reviewing the entire set of rules addressing the allocation of NCPC would be beneficial. The IMM has observed that the total amount of NCPC charged to virtual transactions over the past year has been remarkably high relative to the overall profitability of the positions taken. The imposition of such high transaction costs may threaten the viability of virtual transactions in the day-ahead market, with serious implications for the performance of the day-ahead market (see Section 3.4.7).

2. The IMM recommends that the ISO consider modifying the market rules to allow the FRM threshold price to be calculated daily using a daily fuel-price index. The current FRM design requires market participants with resources assigned to meet an FRM obligation to offer reserve service at an incremental offer price at or above the FRM threshold price. This price is calculated monthly using a monthly fuel-price index and a calculated heat rate. The IMM has observed that volatile fuel prices within a month can result in divergence between daily resource fuel costs and the static monthly threshold price, leading to suboptimal resource offers (see Section 5.1.1).

3. The IMM recommends that the ISO review the way real-time prices are set to ensure that prices reflect supply and demand under all market conditions. The LMP calculator, an automated optimization program, runs every five minutes and generates the ex-post prices used in settlements. One purpose of the LMP calculator is to prevent resource

owners from using underperforming resources to raise prices. However, when resources operate at less than their desired dispatch point, the LMP calculator may produce LMPs that do not reflect scarcity when reserves are insufficient to meet operating reserve requirements (see Section 7.5).

4. When an asset clears in the Day-Ahead Load-Response Program on sequential days, its baseline is carried forward from the period before it cleared. If this baseline is higher than the asset's current consumption, it can receive payments in the DALRP without taking action to reduce load. To prevent the "freezing" of baselines, the IMM recommends adopting an improved process for establishing initial baselines and developing a more robust and accurate baseline methodology (see Section 3.6.4.2).

5. The IMM recommends that the ISO review the DALRP participation and audit rules to prevent a resource from being compensated for a demand reduction under the DALRP during periods when the resource is shut down for reasons unrelated to its participation in the program (see Section 3.6.4.2).

6. The IMM recommends that the ISO reevaluate the asymmetric baseline adjustment rules for the DALRP. While these rules are intended to properly adjust the baseline to reflect rational changes in patterns of consumption leading up to a requested reduction, the approach also provides an opportunity for strategic behavior. The ISO also should reconsider the merits of the rule that allows a customer to carry forward the most favorable baseline adjustment day to day when consecutive event days occur (see Section 3.6.4.2).

7. The IMM recommends revising the rules regarding the failure to follow dispatch and, if appropriate, establishing a definition for failing to follow dispatch for purposes other than NCPC payment and price setting (see Section7.5.4).

Section 2
Overview of New England's Wholesale Electricity Markets and Market Oversight

ISO New England (ISO) is responsible for overseeing and administering New England's competitive wholesale electricity markets. These markets work together to ensure the constant availability of electricity from the bulk power grid for the region's 6.5 million households and businesses and 14 million people. In 2010, more than 450 market participants participated in one or more markets with a combined value of $8.5 billion (energy, capacity, forward reserves, regulation, and daily reliability payments). Participants also have the opportunity to hedge against the costs associated with transmission congestion through Financial Transmission Rights (FTRs) and the associated auction revenue distributions. The wholesale electricity markets and market products in New England are as follows:

- **Day-Ahead Energy Market**—allows market participants to secure prices for electric energy the day before the operating day and hedge against price fluctuations that can occur in real time; facilitates electric energy trading.
- **Real-Time Energy Market**—coordinates the dispatch of generation and demand resources to meet the demand for electricity and to meet reserve requirements.[39]
- **Forward Capacity Market (FCM)**—ensures the sufficiency of installed capacity, which includes demand resources, to meet the future demand for electricity.
- **Financial Transmission Rights (FTRs)**—allows participants to hedge against the economic impacts associated with transmission congestion and provides a financial instrument to arbitrage differences between expected and actual day-ahead congestion.
- **Ancillary services**
    - **Regulation Market**—compensates participants whose resources are controlled by the ISO using automated signals to increase or decrease output moment by moment to balance the variations in instantaneous demand and the system frequency; demand varies second to second, and the system frequency must be kept at a constant rate.
    - **Forward Reserve Market (FRM)**—compensates generators for the availability of their unloaded operating capacity that can be converted into electric energy within 10 or 30 minutes when needed to meet system contingencies, such as unexpected outages.[40]
    - **Real-time reserve pricing**—is the ISO's mechanism to implement *scarcity pricing*, which compensates participants with on-line and fast-start generators for the

[39] *Demand resources* are installed measures (i.e., products, equipment, systems, services, practices, and strategies) that result in additional and verifiable reductions in end-use demand on the electricity network during specific performance hours.

[40] *Unloaded* operating capacity is operational capacity that is not generating electric energy but that could convert to generating energy. A *contingency* is the sudden loss of a generation or transmission resource. A *first contingency* (N-1) is when the first power element (facility) with the largest impact on system reliability is lost. A *second contingency* (N-1-1) takes place after a first contingency has occurred and is the loss of the facility that at that point would have the largest impact on the system.

increased value of their electric energy when the system or portions of the system are short of reserves.[41] It also provides efficient price signals when redispatch is needed to provide additional reserves to meet requirements.

- **Voltage support**—compensates resources for maintaining voltage-control capability, which allows system operators to maintain transmission voltages within acceptable limits.
- **Other services and products**—The ISO procures and compensates participants for other services and products as required by the ISO's *Open Access Transmission Tariff* (OATT).[42] A summary of these payments is provided in Section 8.

The ISO relies on two independent market monitors—the Internal Market Monitor (IMM), and the External Market Monitor (EMM). Every year, the ISO's market monitors review and report on market results and offer insights into the markets' competitiveness and effectiveness as well as areas of market design and operation that need enhancement or improvement.

This section describes the key features of each of the wholesale energy markets the ISO oversees and administers. It also summarizes the market oversight, analysis, and mitigation activities for the New England markets.

2.1 Electric Energy Markets

The primary objective of the electricity markets operated by ISO New England is to ensure a reliable and economic supply of electricity to the high-voltage power grid. The markets include a Day-Ahead Energy Market and a Real-Time Energy Market. In what is termed a *multi-settlement system*, each of these markets produces a separate but related financial settlement.

The Day-Ahead Energy Market produces financially binding schedules for the sale and purchase of electricity one day before the operating day. However, supply or demand for the operating day can change for a variety of reasons, including generator reoffers of their supply into the market, real-time hourly *self-schedules* (i.e., generators' choosing to be on line and operating at a fixed level of output regardless of the price of electric energy), self-curtailments, transmission or generation outages, and unexpected real-time system conditions. Physically, real-time operations balance instantaneous changes in supply and demand and ensure that adequate reserves are available to operate the transmission system within its limits. Financially, the Real-Time Energy Market settles the differences between the day-ahead scheduled amounts of load and generation and the actual real-time load and generation. Participants either pay or are paid the real-time *locational marginal price* (LMP) (see below) for the amount of load or generation in megawatt-hours (MWh) that deviates from their day-ahead schedule.

This section summarizes the key features of the ISO's Day-Ahead and Real Time Energy Markets, including locational marginal pricing; the factors influencing electric energy supply offers, demand bids, and LMPs; and virtual and real-time trading.

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[41] *Fast-start resources* are resources able to respond quickly to system contingencies (i.e., the sudden loss of a generation or transmission resource.

[42] The ISO operates under several FERC tariffs, including the *ISO New England Transmission, Markets, and Services Tariff* (ISO tariff) (2009), of which Section II is the *Open Access Transmission Tariff* (OATT) and Section IV is the *Self-Funding Tariff*. These documents are available at http://www.iso-ne.com/regulatory/tariff/index.html and http://www.iso-ne.com/regulatory/tariff/sect_2/index.html.

2.1.1 Locational Marginal Prices and Pricing Locations

Locational marginal pricing is a way for wholesale electric energy prices to efficiently reflect the value of electric energy at different locations, accounting for the patterns of load, generation, and the physical limits of the transmission system. In New England, wholesale electricity prices are identified at 900 pricing points (i.e., *pnodes*) on the bulk power grid. If the system were entirely unconstrained and had no losses, all LMPs would be the same, reflecting only the cost of serving the next increment of load. This incremental megawatt of load would be served by the generator with the lowest-cost energy offer available to serve that load, and electric energy from that generator would be able to flow to any node on the transmission system LMPs differ generally among locations because transmission and reserve constraints prevent the next-cheapest megawatt (MW) of electric energy from reaching all locations of the grid. Even during periods when the cheapest megawatt can reach all locations, the marginal cost of physical losses will result in different LMPs across the system.

New England has five types of pnodes: one type is an external proxy node interface with neighboring balancing authority areas, and four types are internal to the New England system.[43] The internal pnodes include individual generator-unit nodes, load nodes, *load zones* (i.e., aggregations of load pnodes within a specific area), and the Hub. The *Hub* is a collection of locations with a load-weighted price intended to represent an uncongested price for electric energy; facilitate trading; and enhance transparency and liquidity in the marketplace. New England is divided into the following eight load zones: Maine (ME), New Hampshire (NH), Vermont (VT), Rhode Island (RI), Connecticut (CT), Western/Central Massachusetts (WCMA), Northeast Massachusetts and Boston (NEMA), and Southeast Massachusetts (SEMA).Generators are paid the real-time LMP for electric energy at their respective nodes, and participants serving demand pay the price at their respective load zones.[44] The load-zone price is a load-weighted average price of the load-node prices in that zone.

Import-constrained load zones are areas within New England that must use more expensive generators than the rest of the system because local, inexpensive generation or transmission-import capability is insufficient to meet both local demand and reserve requirements. *Export-constrained load zones* are areas within New England where the available resources, after serving local load, exceed the areas' transmission capability to export excess electric energy.

2.1.2 Electric Energy Supply Offers and Demand Bids

LMPs are determined by supply offers and demand bids. Generator supply offers are influenced by production costs and supplier operating characteristics. For most electricity generators, the cost of fuel is the largest variable production cost, and as fuel costs change, the prices at which generators submit offers in the marketplace change correspondingly. Since fuel prices alone account for a large portion of electricity prices, as fuel prices change year to year, electricity prices change accordingly. The demand bids for electric energy reflect a participant's load-serving requirements and accompanying uncertainty, tolerance for risk, and expectations about congestion on the system caused by transmission constraints. The market-clearing process for the Day-Ahead Energy Market calculates and publishes LMPs at the various pnodes, accounting for supply offers, external transaction offers, virtual (financial) offers and bids, and day-ahead demand bids. The market-

[43] A *balancing authority area* is a group of generation, transmission, and loads within the metered boundaries of the entity (*balancing authority*) that maintains the load-resource balance within the area.

[44] *Market Rule 1* (http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_sec_1-12.pdf) contains provisions that allow participants that meet certain requirements to request nodal pricing for load. However, the number of participants that have exercised this option and the quantity of load these participants serve is very small relative to the zonal load levels.

clearing process for the Real-Time Energy Market is based on supply offers, real-time load, and offers and bids to sell (import) or buy (export) energy over the external interfaces.

2.1.2.1 Actual and Virtual Trading in the Day-Ahead Energy Market

The intersection of the supply and demand curves as offered and bid, along with transmission constraints and other system conditions, determines the Day-Ahead Energy Market price at each node and results in the binding financial schedules and commitment orders (refer to Figure 2-1). Market participants that have *real-time load obligations* (RTLOs) (i.e., they are serving load) may submit demand bids in the Day-Ahead Energy Market. Participants may bid *fixed demand* (i.e., they will buy at any price) and *price-sensitive demand* (i.e., they will buy up to a certain price) at their load zone (or pnode, for some participants that meet certain requirements). Generating units may submit three-part supply offers for their output at the pricing node specific to their location, including start-up, no-load, and incremental energy offers. *Start-up offers* reflect the costs associated with bringing a unit from an off-line state to the point of synchronizing with the grid. *No-load offers* reflect the hourly cost of operating that does not depend on the megawatt level of output. *Incremental energy offers* represent the willingness of participants to operate a resource at higher output levels for higher compensation. The incremental energy offers produce the upward sloping supply curve that is used to calculate the LMP. Market participants have the incentive to submit offers for start-up, no-load, and incremental energy consistent with their true costs to maximize the chance they will be running at profitable levels.

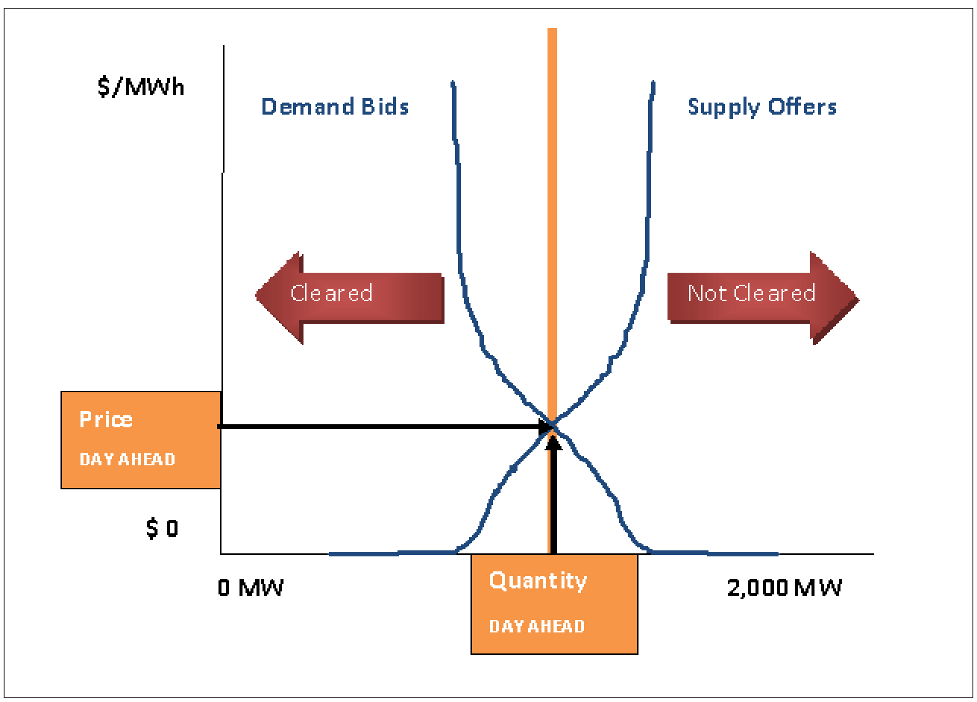

Figure 2-1: Intersection of supply and demand curves indicating the clearing price.

For each megawatt of virtual supply that clears in the Day-Ahead Energy Market, the participant receives the day-ahead LMP and has a financial obligation to pay the real-time LMP at the same location. For each megawatt of cleared virtual demand, the participant pays the day-ahead LMP and receives the real-time LMP at that location. That is, an accepted virtual supply offer in the Day-Ahead

Energy Market is offset by a “purchase” in the Real-Time Energy Market, and a cleared virtual demand bid in the Day-Ahead Energy Market is offset by a “sale” in the Real-Time Energy Market. While these transactions affect the day-ahead prices, they do not represent physical supply or withdrawal of energy in real time. The financial outcome for a particular participant is determined by the difference between the day-ahead and real-time LMPs at the location at which the participant’s offer or bid clears, plus all applicable transaction costs, including daily reliability costs (refer to Section 2.5).

Any participant that satisfies the financial-assurance requirements detailed in the market rules also may bid price-sensitive virtual demand at any pricing node on the system in the Day-Ahead Energy Market. Participants also may offer virtual supply. Virtual trading enables market participants that are not generator owners or load-serving entities (LSEs) to participate in the Day-Ahead Energy Market by establishing virtual (or financial) positions. It also allows more participation in the day-ahead price-setting process, allows participants to manage risk in a multi-settlement environment, and enables arbitrage that promotes price convergence between the day-ahead and real-time markets.

Demand bids and virtual demand bids both can be used to hedge the difference between day-ahead and real-time prices. Demand bids are well suited to hedge RTLOs, and virtual demand bids can be used to arbitrage expected differences between day-ahead and real-time prices at a node or to hedge a nodal load.

2.1.2.2 Real-Time Market Supply and Demand and Generator Commitment

The Real-Time Energy Market is a physical delivery market rather than a financial forward market like the Day-Ahead Energy Market. The Real-Time Energy Market is the environment in which the ISO control room commits and dispatches physical resources to meet actual real-time load, including the minute-to-minute balancing of energy and reserves while accounting for transmission system limits and the need to provide contingency coverage. While the financial schedules produced by the Day-Ahead Energy Market clearing process provide a starting point for the operation of the Real-Time Energy Market, the amount of supply needed and available at each location can increase or decrease for a number of reasons. First, all generators have the flexibility to revise their incremental energy supply offers during the reoffer period.[45] In addition, generating-unit and transmission line outages, along with unexpected changes in demand, can cause the ISO to call on additional generating resources to preserve the balance of supply and demand.

As part of its Reserve Adequacy Analysis (RAA) process, the ISO also may be required to commit additional generating resources to support local-area reliability or to provide contingency coverage, which ensures that the system reliably serves actual demand; the required operating-reserve capacity is maintained; and transmission line loadings are safe. For this process, the ISO evaluates the set of generator schedules produced by the Day-Ahead Energy Market solution, any self-schedules that were submitted during the reoffer period, and the availability of resources for commitment near real time. The ISO will commit additional generation if the Day-Ahead Energy Market generation schedule, plus the self-scheduled resources and available off-line, fast-start generation, does not meet the real-time forecasted demand and reserve requirements that ensure system reliability (see Section 2.3 for more on reserves).

[45] The *reoffer period* is the time spanning 4:00 p.m. and 6:00 p.m. on the day before the operating day during which a market participant may submit revised resource offers.

All the circumstances that affect the level of generator dispatch, such as changes in the level of demand, actual generator availability, and system operating conditions, affect the real-time LMPs. At times, in import-constrained areas, where transmission interfaces limit the flow of economic energy, demand is high relative to local economic supply, and more expensive generation may need to be called on. This results in higher LMPs in that area and lower LMPs on the export side of the interface. In contrast, in export-constrained areas—which contain more low-priced capacity relative to local demand and export capacity—relatively low-cost energy is available to serve load but cannot be dispatched while respecting transmission limitations. These areas can experience lower LMPs compared with unconstrained areas that can more readily export excess supply. Financially, the settlement of the Real-Time Energy Market is based on the deviation between the day-ahead market outcome schedule and the actual production or consumption of electricity in real time.

2.2 Forward Capacity Market

The Forward Capacity Market is a long-term wholesale market that assures resource adequacy, locally and systemwide. It does this by compensating generation and demand resources for fixed capacity costs not covered through the other markets.[46] The market is designed to promote economic investment in supply and demand resources where they are needed most. Capacity resources may be new or existing resources and include supply from power plants, import capacity, or the decreased use of electricity through demand resources. To purchase enough qualified resources to satisfy the region's future needs and allow enough time to construct new capacity resources, Forward Capacity Auctions (FCAs) are held each year approximately three years in advance of when the capacity resources must provide service. Capacity resources compete in the annual FCA to obtain a commitment to supply capacity in exchange for a market-priced capacity payment.

The period between December 2006, when the FCM Settlement Agreement terminated the Installed Capacity Market, and June 1, 2010, when the winners of the first FCA needed to deliver capacity, is referred to as the FCM transition period.[47] The FCM Settlement Agreement prescribed a schedule of fixed payments to resource owners during this time to compensate them for maintaining their availability and developing new capacity.

This section describes the design of the Forward Capacity Market and FCAs and financial-assurance mechanisms and oversight procedures in place for this market.

2.2.1 Capacity Requirements

The capacity needed to satisfy the region's systemwide future load and reliability requirements is called the *Installed Capacity Requirement* (ICR).[48] The *net Installed Capacity Requirement* (NICR) values are the ICRs for the region, minus the tie-reliability benefits associated with the Hydro-Québec

[46] One reason that all fixed costs are not recovered in the energy markets is because a price cap in the energy market limits energy offers to $1,000/MWh.

[47] For background information, see Devon Power LLC, et al., *Explanatory Statement in Support of Settlement Agreement of the Settling Parties and Request for Expedited Consideration and Settlement Agreement Resolving All Issues,* FERC filing, Docket Nos. ER03-563-000, -030, -055 (March 6, 2006; as amended March 7, 2006).

[48] The ICR is the total amount of installed capacity the system needs to meet the Northeast Power Coordination Council (NPCC) loss-of-load expectation criterion (LOLE) to not disconnect load more than one time in 10 years. The ICR is filed with FERC before each auction. For additional information on the LOLE criterion, refer to the ISO's *2010 Regional System Plan* (RSP10) (http://www.iso-ne.com/trans/rsp/2010/index.html) and NPCC criteria at http://www.npcc.org/documents/regStandards/Criteria.aspx (2011).

Phase I/II Interface (termed HQICCs).[49] Other key FCM inputs include locational capacity needs. These ensure that local areas secure sufficient capacity during the auction to maintain reliability when transmission constraints prevent the system from delivering the needed electric energy to the area. The FCM auction assumptions are based on network models that account for the power lines that will be in service no later than the first day of the relevant capacity commitment period.[50] Lines that go in service during the year are not included in the FCM auction assumption.

The locational information is provided for specific *capacity zones* (i.e., geographic subregions of the New England Balancing Authority Area that may represent load zones that are export constrained, import constrained, or contiguous—neither export nor import constrained). Import-constrained areas, which have insufficient local capacity, are assigned a *local sourcing requirement* (LSR) (i.e., the minimum amount of capacity that must be electrically located within these areas to meet the ICR). Export-constrained areas, which have a surplus of capacity, are assigned a *maximum capacity limit* (MCL)—the maximum amount of capacity that can be procured in these areas to meet the ICR.

During each FCA, existing FCM resources are limited to a service period of one capacity commitment period, while new resources may commit to as many as five such periods at the FCA price. Performance penalties for delivery shortfalls during the service period ensure that resources purchased through the auction will be available when needed.

2.2.2 Cost of New Entry

The *cost of new entry* (CONE) is a threshold price used to calculate the starting price for each Forward Capacity Auction.[51] This threshold price is based on the estimated fixed costs for developing capacity resources in the region and the clearing price of previous FCAs. CONEs establish a $/kilowatt (kW)-month value of the cost for an investor to develop, site, and maintain a new simple-cycle gas-fired generator in New England's market. This would include such costs as siting, permitting, developing, and purchasing land, as well as fixed ongoing operation costs, such as staffing, maintenance, taxes, and recovery of the investment over time. The CONE was set at $7.500/kW-month for the first FCA, $6.000/kW-month for the second FCA, and $4.918/kW-month for FCA #3 and FCA #4.

2.2.3 Resource Qualification

Because only resources with a capacity supply obligation (CSO) are required to offer into the Day-Ahead Energy Market, and because only the ICR amount is procured in the auction, it is critical for each FCA to procure only those capacity resources that will be commercial and available at the beginning of each capability year.[52] Although generating, demand, and import resources all may participate in the FCA to receive a CSO, the FCA treats new and existing capacity resources differently. Each type of resource has a distinctive qualification process designed to determine the

[49] As defined in the ISO's tariff, the HQICC is a monthly value that reflects the annual installed capacity benefits of the HQ Interconnection, as determined by the ISO using a standard methodology on file with FERC.

[50] A *capacity commitment period* is also known as a *capability year* and runs from June 1 through May 31 of the following year. *In service* is when a unit or transmission line is available for use.

[51] The cost of new entry also is used for controlling market power concerns with "delist bids" (see below) and in determining reserve pricing (see Section 2.3.2) when supply is inadequate and competition is insufficient.

[52] A *capacity supply obligation* is a requirement for a resource to provide capacity, or a portion of capacity, to satisfy a portion of the ISO's Installed Capacity Requirement that is acquired through an FCA, a reconfiguration auction, or a CSO bilateral contract through which a market participant may transfer all of part of its CSO to another entity.

amount of qualified capacity a particular resource can supply and to certify that each resource can reasonably be expected to be available during the relevant commitment period (approximately three years after the auction).

2.2.3.1 Existing Capacity Resource Qualification

The qualification process for existing capacity resources begins with the ISO's determination of each resource's *summer-qualified capacity* (i.e., the maximum amount of capacity a resource can offer in the FCA during the commitment period's summer portion, which is June through September). For existing resources, the qualification process relies on a resource's demonstrated performance over the previous five years. The ISO also determines each resource's *winter-qualified capacity* for the winter portion of the commitment period (October through May).[53]

At least two weeks before the existing capacity qualification deadline, the ISO notifies existing resources of their qualified capacity to allow time for participants to verify that their qualified capacity is correct or to seek redress by demonstrating that a different capacity quantity is appropriate. All existing resources are included in the auction at the lower of their summer- and winter-qualified capacity. They also are automatically entered into the capacity auction and assume a capacity supply obligation for the relevant commitment period, unless they submit a "delist bid" that subsequently clears in the auction.

Delist Bids. An existing resource can submit a *delist bid* to indicate that it wants to opt out of the auction before the existing capacity qualification deadline and does not want a capacity obligation below a certain price. Several types of delist bids exist:

- *Static delist bids* are submitted for a resource before the auction and cannot be changed during the auction. They may reflect either the cost of the resource or a reduction in ratings as a result of ambient air conditions.[54] The ISO may be required to submit a static delist bid on behalf of a resource if the resource's summer-qualified capacity is greater than its winter-qualified capacity because the resource will not be able to supply its awarded capacity during the winter period.

- *Dynamic delist bids* are submitted by participants during an auction. Unlike other types of delist bids, dynamic delist bids can be offered below 0.8 times the CONE threshold price, and the Internal Market Monitor does not oversee these bids (see below).

- *Permanent delist bids* prohibit resources from participating in any future auctions unless they qualify for and clear as a new resource in a subsequent FCA. Additionally, as of the date of the permanent delisting, permanently delisted resources are prohibited from assuming any capacity obligation.

- *Nonprice retirement bids*, which, are irrevocable requests to retire the entire capacity of a resource, supersede any other delist bids submitted. Nonprice retirement requests are subject to a review for reliability impacts. When the ISO notifies a resource owner of a reliability need for the resource, the resource owner has the option to retire the resource as requested or

[53] The methodology for qualifying intermittent resource capacity, such as wind resources, is contained in *Market Rule 1*, Section III.13, "Forward Capacity Market" (May 1, 2011), http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

[54] "Ambient air" delist bids are those made to reflect that a thermal generator's summer capability is less than its winter capability because high ambient air temperatures can reduce the generator's capacity ratings.

continue to operate it until the reliability need has been met. Once the reliability need has been met, the resource must retire.

- *Export delist bids* are similar to static delist bids but may have an opportunity-cost component as part of the cost data.
- *Administrative export delist bids* are submitted for capacity exports associated with multiyear contracts and are initiated using the same requirements as for export delist bids.

The ISO reviews all delist bids for reliability purposes. Every delist bid submitted is binding and may not be withdrawn or modified after the submittal deadline.[55] Except for permanent delist bids, all delist bids are effective for the relevant commitment period only. All resources with nonpermanent delist bids are considered to be participating anew, without any associated delist bid, at the beginning of the next commitment-period qualification.

Internal Market Monitor Oversight. To address market power concerns, during the qualification process, the IMM reviews certain delist bids to determine whether bid prices are consistent with a resource's net risk-adjusted going-forward costs and opportunity costs as specified in the rules. All delist bids, except dynamic delist bids, must include sufficient documentation for the Internal Market Monitor to make these determinations; the Internal Market Monitor may reject delist bids that have insufficient supporting documentation for the delist price. Static delist bids, export delist bids above 0.8 times the CONE, and permanent delist bids above 1.25 times the CONE are subject to Internal Market Monitor review. Permanent delist bids that are greater than 0.8 times the CONE but less than or equal to 1.25 times the CONE are presumed to be competitive.

The IMM does not review ambient air delist bids and subsequent years of an administrative export delist bid. The IMM also does not review the costs of delist bids, submitted at any time during the auction, at or below 0.8 times the CONE. These bids are dynamic delist bids that are, however, reviewed for any potential reliability need like all other delist bids.

No later than 120 days before the auction, the ISO must notify participants whether their delist bids are qualified to participate in the FCA. All accepted delist bids are entered into the auction. For delist bids excluded from the auction as a result of the Internal Market Monitor's review, the ISO will explain in the notification correspondence the specific reasons for not accepting the bid and the Internal Market Monitor's derivation of an alternate delist price.[56] Subject to applicable market rules, the participant may opt to use this alternate price by informing FERC.

2.2.3.2 New Capacity Resource Qualification

Like existing resources, new supply-side and demand-side resources must undergo a qualification process to be able to participate in the FCM. Additionally, some resources previously counted as existing capacity (including deactivated or retired resources) and incremental capacity from existing

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[55] To provide market transparency to potential new capacity suppliers, all delist bids submitted during the qualification process are posted in advance of the deadline for new resources to submit bids, with the exception of *dynamic delist bids*, which are submitted during the auction.

[56] FERC's FCM Settlement Agreement contained the thresholds for delist bids requiring IMM review: *Order Accepting in Part and Modifying in Part Standard Market Design Filing and Dismissing Compliance Filing.* FERC Docket Nos. ER02-2330-000 and EL00-62-039 (September 20, 2002). 37, http://www.iso-ne.com/regulatory/ferc/orders/2002/sep/er022330-000.pdf.

resources may opt to be treated as new capacity resources in the FCM, subject to certain requirements.

To keep barriers to entry low and increase competition, the financial assurance required from new capacity suppliers is relatively low—a minimal level of credit enables more competitors to enter the market because they are not required to assume a relatively large financial guaranty during the project's development. However, because new commitments can be backed by a relatively low amount of financial security, they must undergo a rigorous qualification process and demonstrate that they can provide the capacity they plan to offer in the auction. This process ensures that any new project that clears in an auction can be interconnected before the delivery period and that the participant can back all capacity obligations with tangible assets to build the project.

New Supply-Side Resources. For new power plant proposals, the ISO conducts several different power studies to ensure that a generator can electrically connect to the power grid without having a negative impact on reliability or violating safety standards. The qualification review also assesses the project's feasibility (i.e., whether it realistically can be built and commercialized before the beginning of the relevant capability year). Each new supply-side resource also must be evaluated to ensure that it would be able to provide effective incremental capacity to the system. An overlapping interconnection impact analysis is conducted for each new supply-side resource to assess whether it is capable of providing useful capacity and electric energy without negatively affecting the ability of other capacity resources to provide these services also.

The first step to qualify a new capacity resource is for project sponsors to submit a new capacity show-of-interest (SOI) form. The SOI form is a short application that requests a minimum amount of information (e.g., interconnection point, equipment configuration, megawatt capacity). By the new capacity qualification deadline, the sponsor also must submit a completed qualification package for the project. This package must include all the data required for the ISO to evaluate the interconnection of the project and its feasibility. Also at this time, new capacity import resources must provide documentation indicating the interface from which the capacity will be imported, the source of the capacity (from an external generating resource or from an adjacent balancing authority area), and the import's summer and winter capability ratings.

New Demand-Side Resources. Demand-reduction resource proposals undergo a feasibility review, during which the ISO ensures that the plans and methods for reducing electricity use meet industry standards. This is the primary mechanism for assessing demand-response project criteria because these projects have no interconnection impact.[57] For this review, demand resources submit a measurement and verification plan, which outlines the project and its development and how the demand reduction is to be achieved. However, some demand-response resources are available only during the summer, and alone, they would not be able to satisfy the year-long delivery requirement. To address this issue, the FCM allows a summer-only resource, such as demand response, to combine its offer with a winter-only resource to form a composite offer. In addition to meeting the same qualification requirements as new and existing resources, demand-resource composite offers also must conform to whatever limitations exist between capacity zones used in the auction. A summer resource inside an import-constrained zone cannot combine with a winter resource outside that zone.

[57] *Demand response* refers to the reduction in consumption of electric energy from the network by market participants in exchange for compensation based on wholesale market prices.

Internal Market Monitor Oversight. Per *Market Rule 1*, the IMM must review offer prices submitted for new resources that intend to remain in the auction below 0.75 times the CONE to confirm that the offer price reflects the long-run cost of the resource.[58] Thus, the qualification packages for these resources must contain supporting cost information for Internal Market Monitor review. If the IMM determines that the offer is inconsistent with the long-run average costs, net of expected noncapacity revenues, capacity that clears at prices below 0.75 times the CONE will be considered to be offered below cost and thus out of market (OOM) for purposes of determining the applicability of the "Alternative Capacity Price Rule."[59]

Notification and Filing. No later than 120 days before each FCA, the ISO notifies each sponsor engaged in the qualification process regarding whether its new capacity resource has been accepted for participation in the FCA, the qualified capacity of that resource, and the Internal Market Monitor's assessment, if the sponsor intends to offer the resource below 0.75 times the CONE. Additionally, all qualification results and auction inputs are filed with FERC. This informational filing is made approximately three months before the ISO conducts the auction and provides interested parties the opportunity to review and comment on the ISO's fulfillment of its responsibilities before conducting the FCA.

2.2.4 Auction Design

Each Forward Capacity Auction is conducted in two stages; a descending-clock auction followed by an auction clearing process. The descending-clock auction, run by an independent auctioneer, consists of multiple rounds. Before the beginning of each round, the auctioneer announces to all participants the start of-round and end-of round prices. During the round, participants submit offers expressing their willingness to keep specific megawatt quantities in the auction at different price levels within the range of the start-of-round and end-of-round prices. During one of the rounds, the capacity willing to remain in the auction at some price level will equal or fall below the ICR, the capacity level the ISO has determined according to North American Electric Reliability Corporation (NERC) standards and Northeast Power Coordinating Council (NPCC) and ISO New England requirements to maintain reliability (see Section 2.2.1).[60] FCM resources still in the auction at this point pass on to the auction-clearing stage.

Table 2-1 shows the hypothetical result of a descending-clock FCA. This example assumes that the CONE is $7.50/kW-month; the ICR equals 30,000 MW; 23,000 MW of existing capacity will be participating, and thus 7,000 MW of new resources will be needed to meet the ICR; and 10,000 MW of new capacity will be participating.

[58] *Market Rule 1,* Section III.13, "Forward Capacity Market" (May 2, 2011), http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

[59] The Alternative Capacity Price Rule ensures that the capacity clearing price reflects the cost of new entry when entry of new resources was prevented because of the presence of out-of-market capacity. This rule sets the clearing price at the lesser of the CONE or the price at which the last new capacity offer left the auction. The rule is described in detail in *Market Rule 1*, Section III.13.2.7.8 (May 2, 2011), http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

[60] For more information on NERC standards, see http://www.nerc.com/page.php?cid=2|20 (NERC, 2011). For more information on NPCC standards, see http://www.npcc.org/regStandards/Overview.aspx (2011).

Table 2-1
Sample Results from a Descending-Clock Forward Capacity Auction

Round	Start-of-Round Price ($/kW-mo)	End-of-Round Price ($/kW-mo)	End-of-Round Resource (MW)	Excess Capacity (MW)
1	$15.00[(a)]	$9.50	33,000	3,000
2	$9.49	$9.00	32,500	2,500
3	$8.99	$8.00	32,000	2,000
4	$7.99	$7.50	31,000	1.000
5	$7.49	$7.00	30,750	750
6	$6.99	$6.00	29,800	−200

(a) The start-of-round price = (CONE x 2).

All the capacity resources that remained in the auction at the end of round six pass through to the second stage of the FCA when market-clearing auction software is run to determine the minimal capacity payment and calculate final capacity-zone clearing prices. This step also includes a post-processing procedure that determines the final payment rate for each resource and its capacity supply obligation for the capacity commitment period. Thus, in the example shown in Table 2-1, after the sixth round, the market-clearing auction software is run to determine the resources and price that minimize cost at a purchase amount of 30,000 MW.

Reconfiguration auctions take place before and during the commitment period to allow participants to buy and sell capacity obligations and adjust their positions. These auctions are needed to add capacity to cover an increased ICR, to release capacity to match a decreased ICR, and to defer capacity requirements associated with existing capacity delist bids. Annual Reconfiguration Auctions (ARAs) to acquire one-year commitments are held approximately two years, one year, and just before the FCA commitment period begins. Monthly and seasonal reconfiguration auctions, held beginning the first month of the first commitment period, adjust the annual commitments during the commitment period.

2.2.5 Capacity Payments

After the FCM transition period ended on June 1, 2010, resources with capacity obligations obtained in the FCAs or subsequent reconfiguration auctions began being paid the auction clearing prices and not the flat rate they received during the transition period.

Two key provisions of the capacity payment structure are the *peak energy rent* (PER) adjustment and availability penalties incurred for unavailability during shortage events. The PER adjustment reduces capacity market payments for all capacity resources when prices in the electric energy markets go above the PER threshold (i.e., *strike*) price, which is an estimate of the cost of the most expensive resource on the system. This usually occurs when electricity demand is high. PER provides an additional incentive for capacity resources to be available during peak periods because capacity payments are reduced for all listed resources, even those not producing energy when the LMP exceeds the PER threshold price. PER also discourages physical and economic withholding in the energy market because a resource that withholds to raise price does not earn energy revenues, while its foregone revenues are deducted from the capacity market settlement.

Shortage events are periods when reserves fall below the system reserve requirements for 30 minutes or more. Shortage-event availability penalties are assessed for resources with capacity supply obligations that are unavailable during defined shortage events. The availability penalties are a disincentive to withhold in the energy market.

2.3 Reserve Markets

To maintain system reliability, all bulk power systems, including ISO New England, need reserve capacity to be able to respond to contingencies, such as those caused by unexpected outages. *Operating reserves* are the unloaded capacity of generating resources, either off line or on line, that can deliver electric energy within 10 or 30 minutes.[61]

ISO operating procedures require reserve capacity to be available within 10 minutes to meet the largest single system contingency (N-1). A resource's ability to provide 10-minute reserve from an off-line state is referred to as "claim-10" capability.[62] Additional reserves must be available within 30 minutes to meet one-half of the second-largest system contingency (N-1-1). The ISO also identifies local second-contingency-protection resources (LSCPRs) to meet the second-contingency requirements in import-constrained areas of New England. A resource's ability to provide 30-minute reserve from an off-line state is referred to as "claim-30" capability. In general, capacity equal to between one-fourth and one-half of the 10-minute reserve requirement must be synchronized to the power system, or be *10-minute spinning reserve* (TMSR), while the rest of the 10-minute requirement may be *10-minute nonspinning reserve* (TMNSR). The entire 30-minute requirement may be served by *30-minute operating reserve* (TMOR) or the higher-quality 10-minute spinning reserve or nonspinning reserve. In addition to the systemwide requirements, 30-minute reserves must be available to meet the local second contingency in import-constrained areas.

In the New England system, participants with resources that provide reserves are compensated through both the locational Forward Reserve Market, which offers a product similar to a capacity product, and real-time reserve pricing. The FRM obligates participants to provide reserve capacity in real time through a competitive, intermediate-term forward-market auction. When the ISO dispatches resources in real time and sets LMPs, the process co-optimizes the use of resources for providing electric energy and real-time reserves. When resources are dispatched to a lower level in real time to provide reserve capacity rather than electric energy, a positive real-time reserve price for the product is set, recognizing the resource's opportunity cost of providing reserve rather than energy. The real-time reserve prices also reflect additional costs to the system for dispatching some other, more expensive resource to provide electric energy to replace the output of the resource that was dispatched down.

The New England system has reserve requirements for its locational FRM and real-time operations. Systemwide requirements exist for TMSR, TMNSR, and TMOR. TMOR requirements exist for reserves in the region's four reserve zones—Connecticut (CT), Southwest Connecticut (SWCT), NEMA/Boston, and the rest of the system (Rest-of-System, ROS). The *Rest-of-System* zone is defined as the area excluding the other, local reserve zones.

[61] Some demand-side resources also can provide reserves; see Section 2.7.

[62] After a unit is upgraded or maintained, it may request a reaudit to have its improved reliability reflected in its claimed values. Changes in total claim-10 and claim-30 capability also can result from new or existing units demonstrating their capability or any time the ISO requests a unit to start.

This section provides an overview of the locational Forward Reserve Market for procuring reserve obligations for winter and summer periods. It also discusses *real-time reserve pricing*, which compensates resources that provide reserves needed in real time, and the ISO's implementation of scarcity pricing.

2.3.1 Forward Reserve Market

The Forward Reserve Market is designed to attract investments in, and compensate for, the type of resources that provide the long-run, least-cost solution to satisfying off-line reserve requirements. The locational FRM compensates participants with resource capacity located within specific subareas for making the type of electric energy market offers that would make them likely to be unloaded and thus available to provide energy within 10 or 30 minutes. Typically, these resources are fast-start units that run infrequently throughout the year (i.e., they have low capacity factors).[63] However, the FRM also compensates resources that commit to be on line without Net Commitment-Period Compensation (NCPC) and have upper portions of the dispatch range that typically are unloaded.[64]

The ISO conducts two FRM auctions, one each for the summer and winter reserve periods (June through September and October through May, respectively), that acquire obligations to provide prespecified quantities of each reserve product. Forward-reserve auction clearing prices are calculated for each reserve product in each reserve zone. When supply offers for forward reserve are not adequate to meet a requirement, the clearing price for that product is set to the price cap, which is $14.00/kW-month.[65] When enough supply is offered under the price cap to meet the requirement for a product in a particular zone, the auction clearing price for that product is set equal to the price of the marginal supply offer. To avoid compensating the same resource megawatt as both general capacity and forward-reserve capacity, before June 1, 2010, actual FRM payments to participants were reduced by the FCM transition rate. Presently, actual FRM payments to participants are reduced by the FCA auction price.

To attract and maintain resources that normally are expected to provide reserves instead of electric energy, the FRM requires the resources designated as forward-reserve resources to offer the megawatt quantity of energy equal to the FRM obligation at or above a threshold price. Participants would not be expected to designate resources that normally are in merit below this level because they would forego the energy revenue from operating.[66] Designating high-incremental-cost peaking resources, on the other hand, does not create a lost opportunity cost because the resource would not be dispatched to provide energy under normal circumstances.

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[63] A *capacity factor* is the ratio of the electric energy a generating unit produced for a certain period of time to the electric energy it could have produced at full operation during the same period.

[64] *Net Commitment-Period Compensation* is a method of providing 'make-whole' payments to market participants with resources that are dispatched out of economic-merit order for reliability purposes when the costs of providing energy or reserves from the resources would otherwise exceed the revenue paid to the market participant. NCPC is paid to resources for providing first- and second-contingency voltage support and control and distribution system protection in either the Day-Ahead or Real-Time Energy Markets. The accounting for the provision of these services is performed daily and considers a resource's total offer amount for generation, including start-up fees and no-load fees, compared with its total energy market value during the day. If the total value is less than the offer amount, the difference is credited to the market participant. For more information, *Market Rule 1*, Appendix F, "Net Commitment-Period Compensation Accounting" (December 24, 2010), http://www.iso-ne.com/regulatory/tariff/sect_3/.

[65] *Market Rule 1*, Section III.9.4, "Forward Reserve Auction Clearing and Forward Reserve Clearing Prices" (March 16, 2011), http://www.iso-ne.com/regulatory/tariff/sect_3/.

[66] *Economic-merit order* (i.e., *in merit* or *in merit order*) is when the generators with the lowest-price offers are committed and dispatched first, and increasingly higher-priced generators are brought on line as demand increases.

The forward-reserve auction clears megawatt obligations that are not resource specific. Before the end of the reoffer period for the Real-Time Energy Market, participants submit electric energy offers that exceed a threshold price for designated resources they control to satisfy the obligation. Before midnight of the day before the operating day, participants that win obligations in a forward-reserve auction must assign physical resources to satisfy their FRM obligations.

The intent of the market design is to set threshold prices to approximate the marginal cost of a peaking resource with an expected capacity factor of 2 to 3%.[67] If the threshold price is set accurately, LMPs should exceed the threshold price only 2 to 3% of the time. A resource offered at exactly the threshold will be dispatched only when the LMP exceeds the threshold price. If the threshold price is set too low, a forward-reserve-designated unit offered at the threshold price will be dispatched to provide electric energy more frequently and therefore will be unavailable to provide reserve. If this occurs more than 2 to 3% of the time, forward-reserve-designated resources will be dispatched more frequently than intended.[68] If participants expected LMPs to regularly be higher than the threshold price, the reserve market could inadvertently attract resources better suited to provide electric energy than reserve.

The reserve obligations incurred in the auction can be met with bilateral transactions as well as any reserve-capable resource in the participant's portfolio. Bilateral trading of forward-reserve obligations allows suppliers facing unexpected unit outages to substitute alternative resources. This feature is useful to suppliers if the cost of expected penalties for nondelivery exceeds the cost of acquiring substitute resources through bilateral transactions. Failure to designate a unit they control or the transfer of the obligation to another participant results in the assessment of a "failure-to-reserve" penalty.

The locational FRM acquires only those resources needed to satisfy off-line reserve requirements, namely TMNSR and TMOR; spinning reserve is not acquired in the forward market. Unlike real-time reserve pricing, the locational FRM auction acquires an amount of off-line reserves specifically within the Rest-of-System zone. This requirement is intended to ensure that real-time reserve resources will be distributed throughout New England rather than concentrated in a few pockets. The ISO tariff requires 600 MW of Rest-of-System TMOR to be available. To meet this requirement reliably, the ISO has established an "R-factor" that is used to set auction requirements. The R-factor increases the amount of systemwide TMOR acquired in the auction to account for real-time failures to start. Currently, the R-factor is set at 1.33.

The cost of paying resources to provide reserves is allocated to market participants on the basis of real-time load obligations in load zones.[69] These obligations are price-weighted by the relative forward-reserve clearing prices of the reserve zones that correspond to each load zone.[70]

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[67] The formula for determining the forward-reserve threshold price is fixed for the duration of the forward-reserve period. This price changes monthly with fuel-price indices and is calculated as a heat rate multiplied by a fuel index. The forward-reserve heat rate also is fixed in the auction notice and does not change during the forward-reserve service period. The threshold price calculation uses the lesser of an index for No. 2 fuel oil and one for natural gas. (A generator's *heat rate*, traditionally reported in Btu/kilowatt-hour (kWh), is the rate at which it converts fuel [Btu] to electricity [kWh] and is a measure of the thermal efficiency of the conversion process.)

[68] A threshold price can be lower than the LMP more than the intended 2 to 3% of the time if the fuel index used in calculating the threshold price is lower than actual fuel prices. The 2 to 3% target also can be surpassed if the system is more frequently tighter than expected, thus requiring the dispatch of less efficient resources. In this case, LMPs will be higher.

[69] *Market Rule 1 Accounting*, Manual 28 (January 7, 2011), http://www.iso-ne.com/rules_proceds/isone_mnls/.

2.3.2 Real-Time Reserve Pricing

The reliable operation of the system requires that real-time operating reserves be maintained for the system as a whole and for identified transmission-import-constrained areas.[71] The ISO's operating-reserve requirements, as established in Operating Procedure No. 8, *Operating Reserve and Regulation* (OP 8), protect the system from the impacts associated with a loss of generating or transmission equipment within New England.[72] According to OP 8, the ISO must maintain a sufficient amount of reserves to be able to recover from the loss of the first contingency within 10 minutes.

In real time, resources are dispatched in the least-cost way to meet the system's requirements for electric energy and reserves simultaneously. The system has real-time reserve requirements (MW) for the following reserve categories:

- System 10-minute spinning reserves
- System 10-minute nonspinning reserves
- System 30-minute operating reserves
- Zonal TMOR for each reserve zone other than the ROS zone

Reserve pricing optimizes the use of local transmission capabilities and generating resources to provide electric energy and reserves. This allows the dispatch software to choose whether transmission should be used to carry electric energy or left unloaded to provide reserves that satisfy zonal reserve requirements. This optimization is based on the real-time energy offers of resources; there are no separate real-time reserve offers. *Real-time reserve credits* are the revenues paid to participants with resources providing reserve during periods with positive real-time reserve prices.

Reserves may be allowed to decline below requirements in real time, such as during ISO Operating Procedure No. 4 (OP 4), *Action during a Capacity Deficiency*, if capacity is short and the system cannot be redispatched to maintain reserve.[73] Before allowing reserves to decline, the system will redispatch resources to maximize the amount of reserves available. Redispatch typically involves decreasing the output of units with fast ramping capabilities that were providing electric energy and increasing the output of slower, more expensive units to replace this energy. The result is the decrease in electric energy output of the faster-ramping resources to provide reserves and the replacement of this lost energy with output from higher-cost resources, which results in higher electric energy prices (LMPs). The resulting real-time reserve prices represent the scarcity of reserves on the system. Local reserve shortages resulting from a complete capacity deficiency are rare. In most cases, reserves can be maintained through the process of redispatch, with appropriate compensation through real-time reserve pricing.

[70] The forward-reserve prices for the ROS reserve zone are used to calculate the charges allocated to load-serving entities in the ME, NH, VT, RI, SEMA, and WCMA load zones. The forward-reserve prices for the SWCT and CT reserve zones are used to calculate the charges allocated to LSEs in the CT load zone, while the forward-reserve prices for the NEMA/Boston reserve zone are used to calculate the charges allocated to the NEMA load zone.

[71] Refer to the ISO's RSP10 for additional information on operating-reserve requirements; http://www.iso-ne.com/trans/rsp/2010/index.html.

[72] Operating Procedure No. 8, *Operating Reserves and Regulation* (January 7, 2011), http://www.iso-ne.com/rules_proceds/operating/isone/op8/index.html.

[73] The OP 4 guidelines contain 16 actions that can be implemented individually or in groups depending on the severity of the situation. OP 4 is available at http://www.iso-ne.com/rules_proceds/operating/isone/op4/.

Reserve Constraint Penalty Factors (RCPFs) are administratively set limits on redispatch costs ($/megawatt hour; $/MWh) the system will incur to meet reserve constraints. Each reserve-requirement constraint has a corresponding RCPF, shown in Table 2-2. The RCPFs are cumulative; the total redispatch cost the system will incur to preserve TMSR is the sum of the RCPFs for TMSR, TMNSR, and TMOR. Similarly, the total redispatch cost the system will incur to preserve TMNSR is the sum of the RCPFs for TMNSR and TMOR. The following table lists the RCPF values.

Table 2-2
New England Reserve Constraint Penalty Factors ($/MWh)

Constraint	Reserve Constraint Penalty Factor
Systemwide TMSR constraint	50
Systemwide total 10-minute reserve constraint	850
Systemwide total 30-minute reserve constraint	100
Local 30-minute reserve constraint[(a)]	250

(a) Before January 1, 2010, this value was $50.

2.4 Regulation Market

Regulation is the capability of specially equipped generators and other energy sources to increase or decrease their output every four seconds in response to signals they receive from the ISO to control slight changes on the system. This capability is necessary to balance supply levels with the second-to-second variations in demand and to assist in maintaining the frequency of the entire Eastern Interconnection.[74] This system balancing also maintains proper power flows into and out of the New England Balancing Authority Area.

The primary objective of the Regulation Market, which is the mechanism for selecting and paying resources needed to manage system balancing, is to ensure that the ISO meets NERC's *Real Power Balancing Control Performance Standard* (BAL-001-0) for balancing authority areas.[75] The primary measure used for evaluating control performance is Control Performance Standard 2 (CPS 2), which is as follows:[76]

> *Each balancing authority shall operate such that its average area control error (ACE) for at least 90% of clock-10-minute periods (six nonoverlapping periods per hour) during a calendar month is within a specified limit, referred to as L_{10}.*[77]

[74] The *Eastern Interconnection* is one of North America's major AC grids that, during normal system conditions, interconnects transmission and distribution infrastructure synchronously operating (at 60-hertz average) east of the Rocky Mountains and south to Florida, excluding Québec and the portion of the system located in the Electric Reliability Corporation of Texas (ERCOT).

[75] This standard (effective May 13, 2009) can be accessed at http://www.nerc.com/page.php?cid=2|20. Additional information on NERC requirements is available at http://www.nerc.com (2011).

[76] More information on NERC's Control Performance Standard 2 is available at http://www.nerc.com/files/Reliability_Standards_Complete_Set.pdf (Resource and Demand Balancing; BAL).

[77] The area control error is the instantaneous difference between the net actual and scheduled interchange (i.e., transfer of electric energy between two balancing authority areas), accounting for the effects of frequency bias and correction for meter error. ACE must be restored to its predisturbance value within 15 minutes, and operating reserves must be restored, as required by the NERC's BAL-002-0, "Resource and Demand Balancing," disturbance control standard (April 1, 2005),

For the New England Balancing Authority Area, the CPS 2 annual average compliance target is 92 to 97%. The ISO periodically evaluates the regulation requirements necessary to maintain CPS 2 compliance. The regulation requirements (posted on the ISO's website) are determined by hour and vary by time of day, day of week, and month.[78]

The regulation clearing price (RCP) is calculated in real time and is based on the regulation offer of the highest-priced generator providing the service. Compensation to generators that provide regulation includes a regulation capacity payment, a service payment, and a unit-specific opportunity cost payment.[79] Unit-specific opportunity cost payments are not included as a component of the regulation clearing price.

2.5 Reliability Costs

To maintain daily system reliability, the ISO is required to make generator commitments that supplement the market-clearing outcomes. Resources that are requested to operate out of merit or do not fully recover short-run operating costs are compensated with Net Commitment-Period Compensation. To maintain long-term reliability, the ISO also administers FERC-approved agreements, called Reliability Cost-of-Service Agreements (Reliability Agreements), with certain generator owners.

This section discusses the types of reliability commitments and the process for making these commitments and allocating costs for resources committed to supplement the market-clearing process. The section also contains information about the Reliability Agreements that compensate generation owners for maintaining resources deemed necessary for the reliable operation of the system.

2.5.1 Daily Reliability Commitments and Costs

The requirements for ensuring the reliability of New England's bulk power system reflect standards developed by NERC, NPCC, and the ISO through open stakeholder processes.[80] These requirements are codified in the NERC standards, NPCC criteria, and the ISO's operating procedures.[81] To meet these requirements, the ISO may commit resources in addition to those cleared in the Day-Ahead Energy Market.

The ISO may commit and dispatch generation to create reserves that allow the system to recover from the loss of the first contingency within the specified time period by providing energy on short notice. Not having these resources committed to operate would pose a threat to the reliability of the system. Generators also can be committed to provide systemwide stability or thermal support or to meet systemwide electric energy needs during the daily peak hours. All generators have a minimum run time, and resources committed for peak hours often are still on line after the peak hours to satisfy

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http://www.nerc.com/files/BAL-002-0.pdf. The ACE of the New England Balancing Authority Area is the actual net interchange minus the biased scheduled net interchange; see *ISO New England Manual for Definitions and Abbreviations—Manual 35*; http://www.iso-ne.com/rules_proceds/isone_mnls/index.html.

[78] The ISO's regulation requirements are available at http://www.iso-ne.com/sys_ops/op_frcstng/dlyreg_req/index.html.

[79] A *regulation opportunity cost payment* is compensation to a pool-scheduled generator for providing regulation service during all or portion of an hour.

[80] For more information on NERC standards, see http://www.nerc.com/page.php?cid=2|20 (2011). For more information on NPCC standards, see http://www.npcc.org/regStandards/Overview.aspx (2011).

[81] The ISO's system operating procedures are available at http://www.iso-ne.com/rules_proceds/operating/isone/index.html.

minimum run-time requirements. The ISO also may commit resources to support second contingencies, to provide reactive power for voltage control or support, or to support local distribution networks. Resources that operate because the ISO requires them to do so but do not recoup their full operating costs (represented by their three-part offers) through electric energy market revenues are paid one of the following types of compensation:

- First-contingency Net Commitment-Period Compensation
- Local second-contingency Net Commitment-Period Compensation
- Voltage reliability payments
- Distribution reliability payments

Systemwide first-contingency costs are financially settled through first-contingency reliability payments paid by the entire system. Local second-contingency commitments costs are settled at the zonal level. The cost of resources committed to provide reactive power for voltage control or support are allocated to transmission owners locally for high voltage and systemwide otherwise. Local transmission-support costs are allocated to the transmission owner requesting the commitment.

2.5.1.1 Reliability Commitment Process

Electric energy market outcomes play an important role in determining the need for out-of-market commitments for reliability. While some commitments may be made before or immediately after the Day-Ahead Energy Market clears as part of the ongoing Reserve Adequacy Analysis, most are made after the reoffer period or later in the RAA process (see Section 2.1.2.2). This process is designed to maximize the opportunity for the market to respond to the need to ensure reliability and to minimize the ISO's supplemental commitments to meet reliability criteria. Based on the RAA, commitments may be added or cancelled during the operating day if reliability needs change as a result of market response or other changed system conditions. When multiple generators are available to meet the RAA requirements, the ISO process selects the resources that will have the lowest total cost for starting and operating the resource at its minimum load for its minimum run time. To the extent that market outcomes and resource self-scheduling result in the commitment of resources needed for local reliability, the ISO does not have to manually commit resources for second-contingency or voltage services.

2.5.1.2 Reliability Commitment Costs

Reliability payments are calculated in both the Day-Ahead Energy Market and the Real-Time Energy Market. First-contingency and second-contingency NCPC payments, voltage-reliability payments, and distribution-reliability payments are made to eligible pool-scheduled generators whose output is constrained above or below the economic level, as determined by the LMP in relation to their offers. This compensation is based on a daily calculation comparing the generators' submitted offer cost for providing electric energy, including start-up and no-load offers and incremental energy offers, to the resources' total energy market revenues for the day. This ensures that generators will follow dispatch instructions made to provide reliability even if a daily loss will result in the energy market at the offer cost. In the electricity industry, these payments are sometimes referred to as *uplift*.

If a generator operates in economic-merit order, most of its compensation will be from the electric energy market. While generators committed to ensure first-contingency coverage (systemwide reliability) may have been in merit during peak hours, they may be out of merit in other hours and will receive first-contingency reliability payments. Or, electric energy market revenues may have been insufficient to cover start-up costs and no-load costs for resources dispatched in economic-merit order to provide energy. First-contingency reliability payments are paid to resources committed by the ISO that do not recover the short-term variable operating costs for the day and are not designated to provide second-contingency reliability or to meet requirements for voltage or distribution system reliability.

2.5.1.3 Daily Reliability Cost Allocations

The out-of-market costs associated with daily reliability payments to generators are allocated to market participants. The allocation of voltage and distribution payments is governed by Section II of the ISO tariff (*Open Access Transmission Tariff*), whereas the allocation of first- and second-contingency payments is governed by Section III of the tariff (*Market Rule 1*).[82] According to the ISO tariff, all New England transmission owners share voltage payments on the basis of network load, and distribution payments are assigned directly to the transmission owners requesting the generator commitment to protect their distribution system.

First-contingency reliability costs in the Day-Ahead Energy Market are charged to participants in proportion to their day-ahead load obligations. In the Real-Time Energy Market, participants whose real-time load deviates from the day-ahead schedule and participants whose generators deviate from day-ahead schedules and are not following real-time dispatch instructions are charged in proportion to these deviations. Second-contingency reliability costs in the Day-Ahead and Real-Time Energy Markets generally are charged to participants in proportion to their load obligations in the respective markets. As part of a 2007 FERC Settlement Agreement, a two-condition, two-tiered threshold criterion was established that can change the allocation of real-time second-contingency charges, such that the charges are allocated to both network load and load obligation.[83]

2.5.2 Reliability Agreements

Reliability Agreements compensate eligible generators with monthly fixed-cost payments for maintaining capacity that provides reliability services. These contractual arrangements, which are subject to FERC approval, provide financial support to ensure that units needed for reliability will continue to be available.

The Reliability Agreements in effect through June 2010 in New England were for full cost of service—the generator recovered its fixed costs in a monthly payment and its variable costs through electric energy offers made at short-run marginal cost. Variable costs not covered by energy market revenues were compensated through daily reliability payments. All capacity market revenues and energy market revenues received in excess of variable costs reduce the monthly fixed-cost payment. Thus, the generator recovered no more than its fixed and variable costs.

2.6 Financial Transmission Rights

As mentioned in Section 2.1.1, transmission constraints can lead to price differences between different locations of the system, and the LMPs throughout the system can be divided into a marginal cost of energy, which is constant across all nodes; the marginal cost of congestion, which is a measure of the cost of transmission congestion; and the marginal cost of physical transmission losses.

[82] The ISO tariff and its subsections are available at http://www.iso-ne.com/regulatory/tariff/index.html.

[83] FERC, *Letter Order Accepting ISO New England Inc.'s 5/18/07 Filing of a Rate Schedule in the Form of an Agreement Reached by the ISO-NE etc, Effective 7/1/07 under ER07-921,* Docket No. ER07-921-000 (June 21, 2007).

The FTR markets and auction revenue distribution rules were designed to allow participants to hedge physical day-ahead congestion costs and to arbitrage FTR auction prices to the expected cost of future congestion. This section discusses the FTR auctions that provide a market-based allocation of future congestion revenue and the administrative distribution of the revenues from these auctions.

2.6.1 FTR Markets

The *financial transmission right* instrument entitles the holder to receive, over a monthly or annual period, a stream of revenues (or obligates it to pay a stream of costs) that arise when the transmission grid is congested in the Day-Ahead Energy Market. The amount is based on the difference between the day-ahead congestion components of the hourly LMPs at each of the two pnodes that define the FTR and its megawatt quantity acquired in the FTR auctions.[84] Participants can acquire FTRs for any path on the system defined by two pricing locations. The origin location of an FTR is called the *source* point, and the FTR delivery location is called the *sink* point. The price of a particular FTR is equal to the difference between the prices at the sink location and the source location in the FTR auction.

The ISO conducts one annual and 12 monthly FTR auctions for buying and selling FTRs. Annual FTRs are offered in a single auction for the ensuing year, and additional monthly FTRs are offered before each month during the year. The auction process also allows participants that may not have physical energy obligations to arbitrage differences between the expected value of an FTR path, defined by the auction price, and the actual value of the FTR path (i.e., the difference between day-ahead congestion components of the source and sink nodes that define the FTR path). Efficient auction outcomes are those that result in average path profits that have a risk-adjusted profit of zero for both on-peak and off-peak FTRs.

The annual FTR auction makes available up to 50% of the transmission system capability expected to be in service during the year. In monthly auctions, up to 95% of the expected transmission capability for the month is available. The total volume of FTRs transacted in each auction is a function of the offers and bids submitted subject to the transmission limits modeled.

2.6.2 FTR Settlements

Hourly congestion revenues from both the Day-Ahead and Real-Time Energy Markets are accumulated in the Congestion Revenue Balancing Fund (CRBF). Day-ahead congestion for any hour will be a positive value if transmission constraints contribute to price separation on the system. In real time, congestion revenue can be either positive or negative because the real-time market settles on deviations from day-ahead schedules.

Whenever there is congestion on the system in the Day-Ahead Energy Market, every FTR will have an hourly positive target allocation (PTA) or negative target allocation (NTA) that accumulates in the CRBF along with day-ahead and real-time congestion revenues. A *positive target allocation* is created when the congestion component at the sink location of the FTR is greater than the congestion component at the source location of the FTR. Holders of FTRs with positive target allocations are owed payments from the CRBF. A *negative target allocation* is created when the day-ahead sink congestion component of an FTR is less than the FTR's source congestion component. An FTR with a negative target allocation becomes a counterflow settlement with payments due to the CRBF.

[84] The minimum quantity for an FTR is 0.1 MW.

The only connection that CRBF target allocations have to the FTR auctions are the megawatt quantities along with the source and sink locations of the FTRs. The prices paid and whether the FTRs were purchased with a negative value (i.e., counterflow FTRs) or a positive value (prevailing-flow FTRs) are irrelevant to the monthly settlement of the FTRs.

2.6.3 Auction Revenue Distribution

The revenue collected during the FTR auctions is distributed to market participants. The ISO tariff includes provisions that allocate this FTR auction revenue back to congestion-paying load-serving entities and transmission customers or owners that have supported the transmission system. The tariff provides two broad classes of participants for the allocation of auction revenues: holders of Qualified Upgrade Awards (QUAs) and holders of Auction Revenue Rights (ARRs). QUAs are assigned to entities that have improved the system's transmission capacity through specific projects, such as generation interconnections, and have accepted QUAs as compensation for a portion of the construction and maintenance of the improved infrastructure rather than network service rights payments. ARRs are the mechanism used to distribute the remainder of the auction revenue to congestion-paying LSEs and transmission customers that have supported the transmission system.

The costs associated with the FTR markets—the administrative costs of holding FTR auctions and settling the FTRs and the potential cost of participants' defaulting on their FTR portfolios—are passed through ISO tariff charges to those with transactions in the FTR market.

2.7 Demand Resources

Along with adequate supply and robust transmission infrastructure, demand resources are an important component of a well-functioning wholesale market. The equipment, systems, services, and strategies that constitute demand resources may include individual measures at individual customer facilities to reduce end-use demand during specific hours, or a portfolio of measures to reduce demand.

While the wholesale electricity markets account for differences in costs of supply that vary with the time and location of consumption, demand resources account for differences in costs of service that vary among customers. Demand resources of all types may provide relief from capacity constraints and promote more economically efficient uses of electrical energy. In the Forward Capacity Market (see Section 2.2), some types of demand-response resources are paid capacity payments and can compete in the Forward Capacity Auction as do other supply-side resources. For example, some customers can reduce their overall energy usage while maintaining the same level of productivity and comfort by implementing energy-efficiency measures. Other customers can supply capacity by eliminating their consumption on short notice in response to a capacity deficiency. Still others may be able to shift end-use customer load onto an on-site emergency generator in response to system emergencies.

The ISO has two broad categories of demand resources: active and passive. *Active demand resources* are dispatchable and respond to ISO dispatch instructions, while *passive demand resources* provide load reductions during previously established performance hours. The ISO-administered demand-resource programs fall into three basic categories: active demand resources that reduce load to support system reliability, active demand resources that respond to wholesale energy prices, and passive demand resources that reduce load through energy-efficiency and similar measures. The ISO's special-purpose demand-response programs differentiate demand-resource owners by cost. This type of customer differentiation arises naturally in competitive markets whenever customer costs differ, and it allows lower-cost customers to reap the benefits of their lower costs. Programs that promote demand resources complement the wholesale electricity markets by offering program choices that recognize different customer costs and capabilities.

The transition to the Forward Capacity Market on June 1, 2010, brought several changes to the ISO demand-response programs. Three programs—Real-Time Profiled Response, Real-Time Two-Hour Demand Response, and Real-Time 30-Minute Demand Response—were retired on May 31, 2010. The asset category of other demand resources also was retired. The Real-Time Price-Response (RTPR) Program and the Day-Ahead Load-Response Program (DALRP), which originally were scheduled to end on June 1, 2010, were extended to May 31, 2012, given the ongoing debate in regional and national forums regarding appropriate compensation rates and cost-allocation practices for price-responsive demand (PRD) participating in wholesale energy markets.[85] Four new programs—Real-Time Demand Response (RTDR), Real-Time Emergency Generation (RTEG), On Peak, and Seasonal Peak—were introduced on June 1, 2010.

The ISO administered the following active-demand-resource programs during all or part of 2010:

- **Real-Time 30-Minute Demand Response Program (retired on May 31, 2010)—**This program required demand resources to respond within 30 minutes of the ISO's instructions to interrupt.
- **Real-Time Two-Hour Demand Response Program (retired on May 31, 2010)—**This program required demand resources to respond within two hours of the ISO's instructions to interrupt.
- **Real-Time Profiled Response Program (retired May 31, 2010)—**This program was designed for enrolling participants with loads under their direct control that are capable of being interrupted within two hours of the ISO's instructions to interrupt. Individual customers participating in this program were not required to have an interval meter.[86] Instead, enrolling participants developed and submitted to the ISO for approval a measurement and verification plan, as specified in the ISO's *Load Response Program Manual*.[87]
- **Real-Time Demand-Response Resources (effective on June 1, 2010)—**Resources in this program must curtail electrical usage within 30 minutes of receiving a dispatch instruction from the ISO. These resources are dispatched when the ISO forecasts OP 4 Action 2 or higher the day before the operating day, or implements OP 4 Action 2 or higher during the operating day. OP 4 Action 2 is the action the ISO takes to dispatch real-time demand resources in the amount and location required in response to the depletion of 30-minute operating reserve. Registered real-time demand-response assets have the option of participating in the DALRP.
- **Real-Time Emergency Generation Resources (effective on June 1, 2010)—**RTEG is distributed generation the ISO calls on to operate during a 5% voltage reduction that requires more than 10 minutes to implement (i.e., OP 4 Action 6 or more severe actions) but must limit its operation to 600 MW to comply with the generation's federal, state, or local air quality permit(s), or combination of permits, and the ISO's market rules. RTEG operations

85 *Demand-Response Compensation in Organized Wholesale Energy Markets*, 18, CFR § 35 (March 15, 2011), http://www.iso-ne.com/regulatory/ferc/orders/2011/mar/rm10-17-000_3-15-000_demand_resp_order.pdf.

86 An *enrolling participant* is the market participant that registers customers for a load-response program.

87 *Real-Time Price Response and Day-Ahead Load Response Programs*, Manual M-RTPRP/DALRP (June 1, 2010), http://www.iso-ne.com/rules_proceds/isone_mnls/index.html.

result in curtailing load on the grid as the distributed energy provided by the emergency generator begins serving demand. Real-time emergency generators must be available from 7:00 a.m. to 7:00 p.m. Monday through Friday on nonholidays, they must begin operating within 30 minutes of receiving a dispatch instruction, and they must continue operating until receiving an ISO instruction to shut down.

In 2010, these programs were activated to help preserve system reliability during zonal or systemwide capacity deficiencies. Program assets were called on in accordance with OP 4 procedures. Before June 1, 2010, the OP 4 contained guidelines for 16 actions implemented individually or in groups, depending on the severity of the situation. Before June 1, 2010, the Real-Time Two-Hour Demand-Response and Real-Time Profiled-Response Programs were activated at Action 3, and the Real-Time 30-Minute Demand-Response Program was activated at Actions 9 and 12. The assets activated at Action 12 (typically customer-owned emergency generators) may have had environmental permit limitations that necessitated the system operator to implement voltage reductions before their operation. Beginning June 1, 2010, some of the assets that participated in one of the first three programs listed above, which have since been retired, began participating in the FCM as RTDR resources or as RTEG resources.[88]

The ISO administered the following active-demand-resource programs during 2010:

- **Real-Time Price-Response Program—**a separate real-time demand-response program that involves voluntary load reductions by program participants eligible for payment when the day-ahead or forecast hourly real-time LMP is greater than or equal to $100/MWh and the ISO has transmitted instructions that the eligibility period is open. Participants are paid the higher of $100/MWh or the real-time LMP.
- **Day-Ahead Load-Response Program (DALRP)—**an optional program that allows participants enrolled in the active-demand-resource category that reduce load to support system reliability (with the exception of RTEG resources) and participants enrolled in the Real-Time Price-Response Program to offer interruptions in response to Day-Ahead Energy Market prices. If an offer clears, the participant is paid the day-ahead LMP and is obligated to reduce load by the amount cleared day ahead.[89] The participant then is charged or credited at the real-time LMP for any deviations in curtailment in real time relative to the amount cleared day ahead.

The ISO administered the following passive-demand-resource programs during all or part of 2010:

- **Other demand resources (ODRs) (retired on May 31, 2010)—**Resources that were enrolled in this program included energy efficiency, load management, and distributed generation projects implemented by market participants at retail customer facilities. These resources tended to reduce end-use demand on the electricity network across many hours but usually not in direct response to changing hourly wholesale energy price incentives. ODRs were paid capacity transition payments similar to supply-side resources.

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[88] A real-time demand-response *resource* or a Real-Time Emergency Generation *resource* can be an aggregation of one or more RTDR *assets* or RTEG *assets*, respectively, located within the same load zone or dispatch zone.

[89] This clearing process takes place after the close of the Day-Ahead Energy Market and does not play a role in setting the day-ahead LMPs.

- **On-peak resources (effective on June 1, 2010)—**These resources do not receive dispatch instructions from the ISO. Instead, they curtail their electricity use at set times throughout the year. On-peak resources must reduce consumption during summer peak hours (nonholiday weekdays, 1:00 p.m. to 5:00 p.m., during June, July, and August) and winter peak hours (nonholiday weekdays, 5:00 p.m. to 7:00 p.m., during December and January).
- **Seasonal-peak resources (effective June 1, 2010)—**These resources do not receive dispatch instructions from the ISO. Instead, they curtail their electricity use at set times throughout the year. Seasonal-peak resources must reduce consumption during the summer months of June, July, and August and during the winter months of December and January in hours on nonholiday weekdays when the real-time system hourly load is equal to or greater than 90% of the most recent "50/50" system peak-load forecast for the applicable summer or winter season.[90]

2.8 Market Oversight and Analysis

ISO New England's market monitoring structure relies on the ISO's Internal Market Monitor (IMM) and External Market Monitor (EMM), which currently is Potomac Economics. The Internal Market Monitor reports administratively to the company's chief executive officer, whereas both market monitors report functionally to the ISO Board of Directors through its Markets Committee. The Internal Market Monitor seeks input from the EMM to provide another independent review of significant market developments.

This reporting structure is analogous to the oversight structure of internal and external auditors in corporate finance. The functional reporting directly to the Markets Committee of an independent board provides the IMM with the independence vital to its obligation to inform regulators of any significant problems. The administrative reporting to the company's chief executive officer and day-to-day interaction with operational staff prevent the IMM from becoming isolated and support the ISO's responsibility to ensure that the New England markets and prices are transparent and competitive.

This section provides information on the specific role of the market monitoring unit in responding to violations of the market rules.

2.8.1 Role of Market Monitoring

Through the following five general monitoring activities, the IMM ensures that prices properly reflect competitive supply and demand conditions and assists FERC in enhancing the competitiveness of wholesale electricity markets for the benefit of consumers:

- Monitoring day-to-day participant behavior and market outcomes
- Mitigating participant behavior found to be anticompetitive as outlined in *Market Rule 1*[91]

[90] The 50/50 "reference" case peak loads have a 50% chance of being exceeded because of weather conditions. For the reference case, the summer peak load is expected to occur at a weighted New England-wide temperature of 90.2ºF, and the winter peak load is expected to occur at 7.0ºF. A 90/10 "extreme" case peak load has a 10% chance of being exceeded because of weather. For the extreme case, the summer peak is expected to occur at a temperature of 94.2ºF, and the winter peak is expected to occur at a temperature of 1.6ºF.

[91] *Market Rule 1* and appendixes are available at http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

- Investigating participant behavior that existing tariff provisions do not explicitly preclude but that may be considered anticompetitive; making a referral to FERC for further analysis and possible sanctions when such behavior or anticompetitive outcomes are identified

- Evaluating and reporting on existing market rules, operating procedures, and market outcomes and making recommendations for improvements

- Evaluating new ISO initiatives and market design proposals to ensure that the revisions will support the efficient operation of competitive wholesale electricity markets

The IMM fulfills these activities by performing the following specific tasks:

- Identifying potential anticompetitive behavior by market participants

- Implementing the mitigation provisions of *Market Rule 1* when appropriate

- Immediately notifying appropriate FERC staff of instances in which the behavior of a market participant may require an investigation and evaluation to determine whether the participant has violated a provision of the ISO tariffs, market-behavior rule, or the *Energy Policy Act of 2005* (EPAct) (see below)[92]

- Providing support to the ISO in administering FERC-approved tariff provisions covering the ISO-administered markets

- Identifying ineffective market rules and tariff provisions and recommending proposed rule and tariff changes that will promote wholesale competition and efficient market behavior

- Providing comprehensive market analysis to evaluate the structural competitiveness of the ISO-administered markets and the resulting prices to identify whether markets are responding to customers' needs for reliable electricity supply at the lowest long-run cost

- Providing regular reports to the ISO's senior management and board of directors and state and federal regulatory agencies that describe and assess the development and performance of wholesale markets, including performance in achieving customer benefits, providing transparency, and meeting federal reporting guidelines

- Evaluating proposed changes in market rules and market design

The *Energy Policy Act of 2005* grants FERC broad authority to regulate manipulative or fraudulent behavior in the energy markets. FERC implemented its new authority by amending its existing regulations to prohibit any entity from directly or indirectly engaging in the following behavior in connection with the purchase or sale of electric energy or transmission services subject to its jurisdiction:

- Using or employing any device, scheme, or artifice to defraud
- Making any untrue or misleading statement

[92] *Energy Policy Act of 2005*, Pub. L. No.109-58, Title XII, Subtitle B, 119 Stat. 594 (2005) (amending the *Federal Power Act*).

- Engaging in any fraudulent or deceptive act, practice, or course of business

These rules are intended to work in conjunction with the enhanced civil penalty authority extended to FERC as a component of EPAct. The Internal Market Monitor is obligated to refer to FERC any finding of a potential violation of EPAct or the market-behavior rules.

2.8.2 Market Monitoring and Mitigation

As specified in *Market Rule 1*, the IMM monitors the market impact of specific bidding behavior (i.e., offers and bids) and, in specifically defined circumstances, mitigates behavior that interferes with the competitiveness and efficiency of the energy markets and daily reliability payments. Whenever one or more participants' offers or declared generating-unit characteristics exceed specified offer thresholds and market-impact thresholds, or are inconsistent with the behavior of competitive offers, the IMM substitutes a default offer for the offer submitted by the participant. These criteria are applied each day to all participants in constrained areas. A less restrictive set of thresholds is applied each day to systemwide pivotal suppliers.

2.8.3 ISO Self-Funding Tariff and the *Open Access Transmission Tariff*

The ISO operates under the *ISO New England Transmission, Markets, and Services Tariff* of which Section II is the *Open Access Transmission Tariff* and Section IV is the *Self-Funding Tariff*.[93] In addition to defining the rules and responsibilities of the ISO and market participants, the tariff outlines various schedules that define the revenues the ISO is to collect for its operations and for compensating transmission owners for constructing and maintaining the transmission infrastructure controlled by the ISO and providing ancillary services for which markets do not exist.

The ISO *Self-Funding Tariff* contains rates, charges, terms, and conditions for the functions of the ISO. These services are as follows:

- **Schedule 1: Scheduling, System Control, and Dispatch Service—**scheduling and administering the movement of power through, out of, or within the balancing authority area
- **Schedule 2: Energy Administration Service (EAS)—**charges for services the ISO provides to administer the energy markets
- **Schedule 3: Reliability Administration Service (RAS)—**charges for services the ISO provides to administer the reliability markets

The OATT addresses the collection and distribution of payments for the following transmission services:

- **Schedule 1: Scheduling, System Control, and Dispatch Service—**involves scheduling and administering the movement of power through, out of, or within the New England Balancing Authority Area.
- **Schedule 2: Reactive Supply and Voltage Control (VAR)—**provides reactive power to maintain transmission voltages within acceptable ranges. Schedule 2 also includes calculations for capacity costs.

[93] These documents are available at http://www.iso-ne.com/regulatory/tariff/index.html and http://www.iso-ne.com/regulatory/tariff/sect_2/index.html.

- **Schedule 8: Through or Out Service (TOUT)—**includes transactions that go through the New England Balancing Authority Area or originate on a pool transmission facility (PTF) and flow over the PTF before passing out of the New England Balancing Authority Area. Transmission customers pay the PTF rate for TOUT service reserved for them with respect to these transactions.
- **Schedule 9: Regional Network Service (RNS)—**is an ISO accounting service for regional network services. RNS allows network customers to efficiently and economically use their resources, internal bilateral transactions, and external transactions to serve their network load located in the New England area.
- **Schedule 16: System Restoration and Planning Service (Black Start)—**plans for and maintains adequate capability for the restoration of the New England Balancing Authority Area following a blackout.
- **Schedule 19: Special-Constraint Resource (SCR) Service of the *Open Access Transmission Tariff*—**includes the payments and charges for the out-of-merit commitment or operation of resources at the request of transmission owners or distribution companies to manage constraints not reflected in the ISO systems.

Section 3
Energy Market

This section describes the competitiveness and outcomes of the ISO's Day-Ahead and Real-Time Energy Markets. It also includes a discussion of congestion revenues, Financial Transmission Rights, reserve pricing, and demand resources. On the basis of its review of market outcomes, the IMM concludes that the wholesale electric markets operated competitively in 2010. Market outcomes were heavily influenced by fuel-price increases and higher loads, especially during the summer months. As described in more detail in this section, the increase in fuel prices and load growth caused energy, congestion, and reliability costs to increase. Also contributing to higher costs were a lower level of hydroelectric production from run-of-river and pondage hydroelectric units and the extended, unexpected outage of a large resource from May to December 2010.

The IMM undertook a specific review of system and market performance on two days in 2010 on which a combination of high loads and forced outages resulted in unusual operating conditions that required the system operators to initiate operating procedures to maintain reliability. On June 24, the total system capacity dropped below the level needed to meet load plus operating reserve, and several actions of OP 4 were called.[94] On September 2, the trip of a large generating unit forced the operators to dispatch all capacity available within 10 minutes to restore the area control error (see Section 2.4). The review of performance on these days led to several recommendations, described below and in Section 7.

3.1 Market Competitiveness and Efficiency

Over the long run, competitive and efficient electricity markets provide the incentives to maintain an adequate supply of electric energy at prices consistent with the cost of providing it. To assess the competitiveness of the wholesale electric energy markets in New England, the IMM examined two types of measures—structural measures that look at market concentration and price-based measures that compare price outcomes to the marginal cost of production:

- **Structural Measures**
    - **Herfindahl-Hirschman Index (HHI)—**measures market concentration of generating capacity. An HHI below 1,500 indicates a low concentration and therefore a market less susceptible to the exercise of market power.
    - **Residual Supply Index (RSI)—**measures the hourly percentage of load in megawatts that can be met without the largest supplier. Suppliers whose output is required to satisfy demand are termed "pivotal" and often can unilaterally affect market prices.
- **Price-Based Methods**
    - **Competitive benchmark price model—**calculates electricity prices for each hour using actual system demand and a supply curve based on available generating

[94] OP 4 refers to ISO New England Operating Procedure No. 4, *Action during a Capacity Deficiency* (December 10, 2010), http://www.iso-ne.com/rules_proceds/operating/isone/index.html.

resources. The competitive benchmark calculation compares two different runs of the competitive benchmark model. One model run uses the actual supply offers submitted by participants for each day (offer prices). The other run uses supply offers based on the IMM's estimates of short-run variable costs. The results are used to calculate the Quantity-Weighted Lerner Index (QWLI) to assess the competitiveness of market outcomes.

- **Correlated movement of input fuel price and electric energy prices—**assesses the statistical relationship between electric energy prices and the price of natural gas, which is the input fuel for the generating resources that most frequently set LMPs in the region.

This section presents the analyses of competitive market conditions during 2010 for the ISO's electric energy markets.

3.1.1 Structural Tests for Competition

Figure 3-1 shows the generation capability of the 10 lead participants with the largest portfolios as of July 1, 2010.[95] As in the previous year, the largest owner was Dominion Energy Marketing, with about 4,900 MW; followed by NextEra Energy, with 3,500 MW; and Boston Generating, with 2,700 MW. New England's largest provider, Dominion, has a 16% market share, while NextEra Energy has an 11% market share. The total supply from all other participants, excluding the top 10 participants, is roughly 11,000 MW, or 36%.

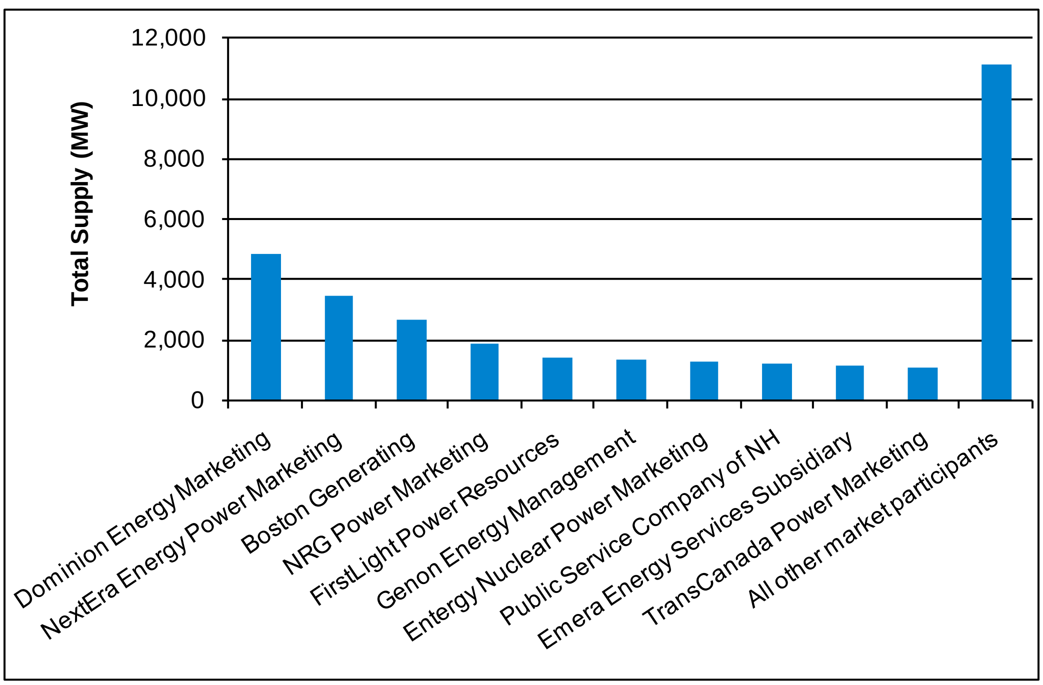

Figure 3-1: Generation capacity by lead participant, 2010, 1,000 MW and above.

[95] A *lead participant* is a company representing a resource in the ISO systems.

3.1.1.1 Herfindahl-Hirschman Index

Market concentration is a function of the number of firms in a market and their respective market shares. For electricity markets, market share is estimated as the percentage of capacity (measured in megawatts) controlled. The Herfindahl-Hirschman Index, a commonly used measure of market concentration, is calculated by summing the squares of each participant's market share. The HHI gives proportionately greater weight to the market shares of the larger firms, consistent with their greater importance in competitive interactions. Market concentration measured by the HHI typically is divided into three categories:[96]

- Unconcentrated markets (HHI below 1,500)
- Moderately concentrated markets (HHI between 1,500 and 2,500)
- Highly concentrated markets (HHI above 2,500)

These classifications are only indicative since a low-concentration index does not guarantee that a market is competitive; however, higher values generally indicate greater potential for participants to exercise market power.

Monthly systemwide HHIs for New England, based on the summer capabilities of all lead participants' internal resources, averaged 626 in 2010. This value has not changed noticeably over the past three years. It indicates that the New England electric energy markets are well within the "not concentrated" range. However, the systemwide HHI ignores transmission constraints and therefore does not reflect the extent of market power in load pockets.[97] On the other hand, systemwide HHI does not account for contractual entitlements to generator output, which can decrease the incentive for resources to exercise market power. To address these deficiencies, the IMM analyzes other measures of competitiveness.

3.1.1.2 Residual Supply Index Analysis

The Residual Supply Index is the percentage of demand (in megawatts for a given hour) that can be met without the largest supplier. When the RSI exceeds 100%, the system has sufficient capacity from other suppliers to meet demand without any capacity from the largest supplier. When the RSI is below 100%, a portion of the largest supplier's capacity is required to meet market demand, and the supplier is pivotal. A pivotal supplier can drive prices above the competitive level, subject only to offer caps, mitigation measures, and the price elasticity of demand. As RSIs rise, the ability of market participants to exert market power decreases. In addition to reporting the hours when the RSI is below 100%, Market Monitoring reports on the number of hours the RSI is less than 110% to capture situations in which a single supplier cannot exercise market power but the level of competition in that hour is low.

Figure 3-2 shows RSIs for 2010. RSIs generally are lowest during periods of high demand, indicating a drop in the level of competition as the system approaches its capacity limit. This analysis shows that

[96] US Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines* (Washington, DC: US Department of Justice and Federal Trade Commission, August 19, 2010), http://www.justice.gov/atr/public/guidelines/hmg-2010.html.

[97] *Load pockets* are areas of the system in which the transmission capability is not adequate to import energy from other parts of the system and demand is met by relying on local generation (e.g., Southwest Connecticut and the Boston area).

pivotal suppliers existed at the system level during a total of 223 hours during five months in 2010, an increase from 2009 when 46 such hours were spread over one month. The RSI was less than 110% for 650 hours in 2010, an increase from 2009 when the RSI was less than 110% for 159 hours. The monthly minimum RSIs ranged from 82% in September 2010 to 126% in March 2010. New England had RSIs with values below 100% from May through September 2010. The average monthly values ranged from 124% in July to 156% in March. The higher-than-average temperatures during summer contributed to high loads and consequently higher RSIs.

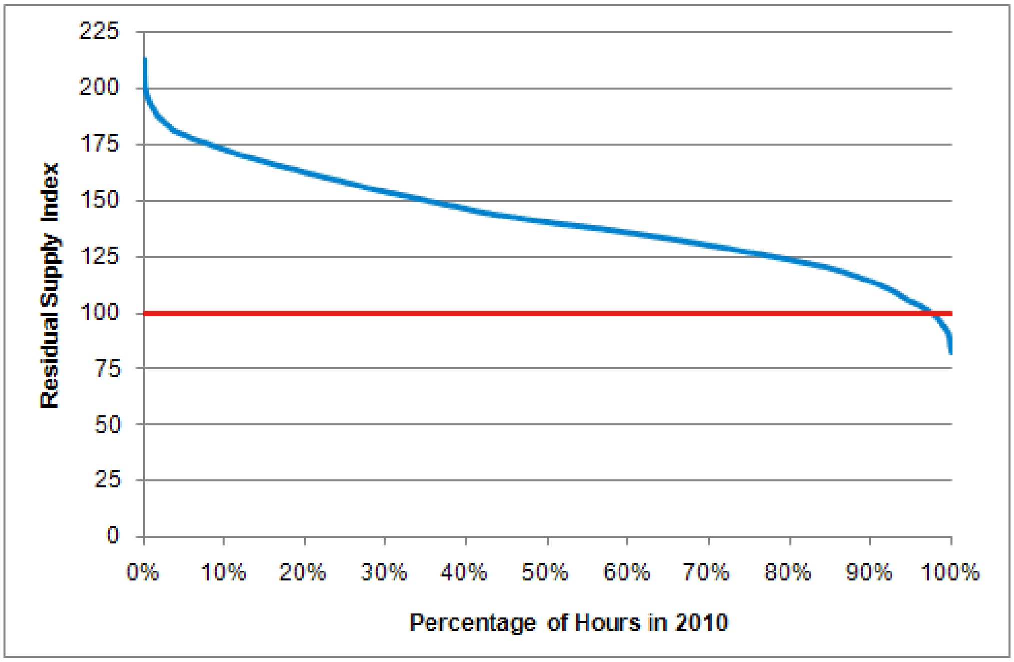

Figure 3-2: Residual Supply Index duration curve for the entire New England market, 2010.

To measure potential local market power caused by import constraints, the IMM analyzed local RSIs for May, June, July, August, and September 2010. The analysis included the SWCT, CT, and NEMA/Boston reserve zones (see Section 2.3).These areas were chosen because they often are import constrained or have concentrated ownership.

Table 3-1 shows the results of that analysis. RSIs in the local zones were noticeably higher than the systemwide RSI. There were RSIs below 100% in many hours, indicating the existence of a pivotal supplier with the potential to exercise market power. A single participant was pivotal in each reserve zone. In 2010, some of the lowest RSIs in local areas were during maintenance In the CT local reserve zone, a supplier was pivotal up to 15% of the time. The NEMA/Boston local reserve zone was slightly more concentrated, with a pivotal supplier in 37% of total hours. This represents an increase from last year's value due to tighter local supply and demand conditions. However, these values are much lower than the 2008 values because of the completion of transmission projects in NEMA. The RSI analysis suggests that suppliers in the local reserve zones may have the ability to exercise market power. However, the offer-mitigation measures for resources in constrained areas protect buyers by severely limiting the ability of suppliers with market power from using it to raise prices.

Table 3-1
Local Area RSI Calculations for Selected System Interfaces, 2010

Reserve Zone	Month	# of Hours RSI <100%	# of Hours RSI <110%	% Hours RSI <100%	% Hours RSI <110%	Average Monthly RSI	Maximum RSI	Minimum RSI
SWCT	May	0	0	0%	0%	181	258	129
	Jun	0	0	0%	0%	172	258	122
	Jul	0	0	0%	0%	160	214	121
	Aug	0	0	0%	0%	161	231	115
	Sep	0	60	0%	8%	155	265	104
CT	May	40	85	5%	11%	137	198	92
	Jun	16	64	2%	9%	137	195	92
	Jul	111	280	15%	38%	122	184	85
	Aug	46	161	6%	22%	131	188	91
	Sep	37	92	5%	13%	135	190	94
NEMA	May	149	300	20%	40%	118	180	79
	Jun	268	405	37%	56%	112	165	86
	Jul	196	352	26%	47%	115	164	80
	Aug	114	236	15%	32%	121	165	88
	Sep	91	282	13%	39%	120	168	89

3.1.2 Price-Based Measures of Competitiveness

Price-based measures provide insight into the offer behavior of participants. If the market is competitive, at equilibrium, prices should approximate the marginal cost of the marginal (or price-setting) unit.

3.1.2.1 Competitive Benchmark Analysis

The competitive benchmark (benchmark price) is a model-derived estimate of the market-clearing price that would have resulted had all market participants offered their electric energy at marginal cost and the system had been unconstrained.[98] The model calculates the benchmark price in each hour by estimating the cost of the next megawatt (i.e., incremental cost) from the least expensive generating unit capable of producing one more megawatt. The benchmark price in an hour accounts for production costs, including environmental and variable operations and maintenance (O&M) costs, unit availability, and net imports.

Table 3-2 compares the annual average benchmark price with a second modeled price, the offer-intercept price. The offer-intercept price is derived using the same model as the benchmark price, but

[98] The tool evaluates the competitive performance of New England's wholesale electricity markets using a method similar to one developed by Bushnell and Saravia of the University of California Energy Institute. See James Bushnell and Celeste Saravia, *An Empirical Analysis of the Competitiveness of the New England Electricity Market* (Berkeley: University of California Energy Institute, January 2002), http://www.iso-ne.com/pubs/spcl_rpts/2002/empir_assess_competitiveness_bushnell.pdf.

instead of using generator costs, it uses generators' actual supply offers. The difference between the benchmark price and the offer-intercept price measures the competitiveness of the market. Having only small differences between the two metrics indicates that modeled prices based on generator offers are close to modeled prices based on generator costs, which would support a conclusion that the market is competitive. Larger differences would indicate that the market was not as competitive. The metric used to compare the different price estimates is the Quantity-Weighted Lerner Index, a variant of the conventional Lerner Index. The conventional Lerner Index is widely used to assess the competitiveness of market outcomes and is calculated as "price minus marginal cost divided by price." The QWLI substitutes the model-based offer-intercept price for the "market price" in the Lerner index.

Table 3-2
Quantity-Weighted Lerner Index, %[(a)]

2004	2005	2006	2007	2008	2009	2010
−6	1	1	2	−1	5	6

(a) The QWLI = [(annual market cost based on market prices − annual market cost based on marginal cost estimates)/annual market cost based on market prices].

While the QWLI does measure the price-cost markup, it is subject to estimation error in both the model and marginal costs. Consequently, its primary diagnostic value is how it changes over time. In assessing whether changes over time reflect a change in the markets competitiveness, keeping in mind the difficulty of precisely measuring prices and costs is helpful. One measure of this uncertainty is the 10% markup over costs that the market monitor for PJM uses to calculate mitigated bids for the PJM energy market.[99] Thus, year-to-year changes of less than 10%, such as those seen over the past several years, are not likely to reflect changes in the market's competitiveness. Given these modeling and estimation limits, the IMM determined that the recent QWLI results are consistent with competitive market outcomes.

3.1.2.2 Comparison of Fuel Prices and Electric Energy Prices

Another indicator of market competitiveness is how electricity prices respond to input cost changes. Since fuel costs are by far the largest short-term cost component of generating electricity, electricity prices should change as fuel prices, especially the price of the marginal fuel, change. In New England, natural gas is the marginal fuel over 71 % of the time, so the IMM's analysis focuses on the relationship between the wholesale price of electricity and the cost of natural gas. More specifically, this section compares the average monthly percentage change in the prices of electricity and natural gas from 2009 to 2010. The IMM calculated the correlation between natural gas and on-peak real-time energy prices (Hub LMPs) to determine whether electricity prices varied with natural gas prices. The correlation for 2010 was about 0.94, meaning that the variance in natural gas prices explains about 90% of the variance in on-peak real-time Hub LMPs. This analysis and the examination of market results below shows that electric energy prices reflect the costs to suppliers of producing electric energy (i.e., largely fuel costs), which is consistent with the finding that the market is competitive.

[99] PJM stands for PJM Interconnection LLC, the RTO for all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and the District of Columbia.

Figure 3-3 shows indices for fuel prices and the cost of electricity at the Hub normalized to January 2009. In the summer of 2010, real-time LMPs fell less than natural gas prices for two main reasons. First, oil units were dispatched and set prices more frequently, especially during the peak load hours, and second, the frequency and magnitude of real-time reserve prices increased compared with summer 2009, also increasing the real-time LMP.

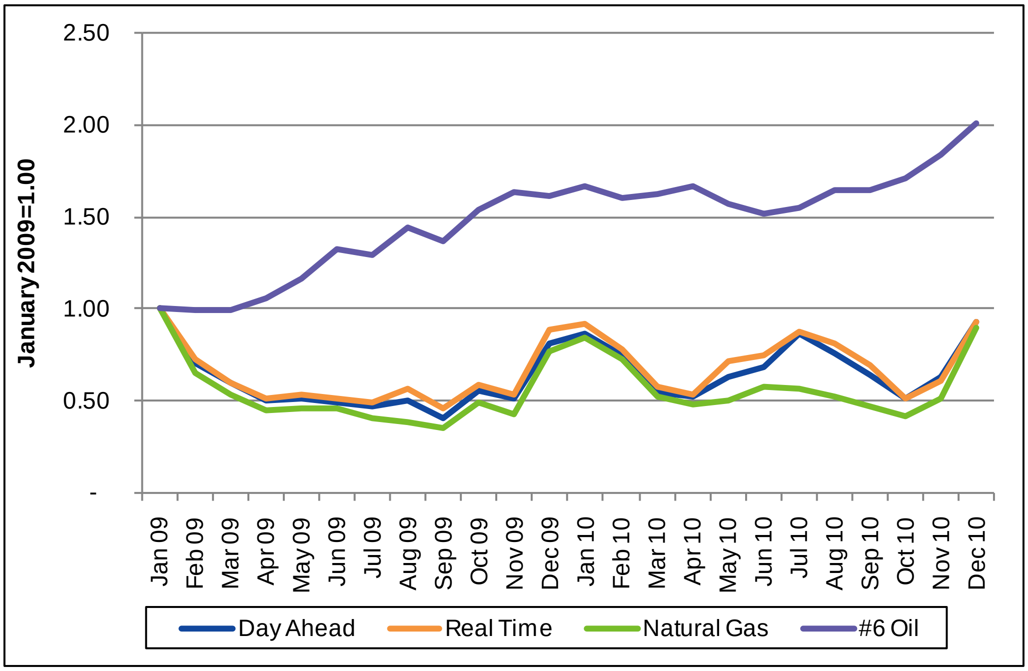

Figure 3-3: Monthly fuel prices for natural gas and No. 6 oil and day-ahead and real-time Hub indices, 2009 to 2010, compared with January 2009.

Source: Natural gas price information provided by the Intercontinental Exchange, Inc. (ICE); http://www.theice.com.

Figure 3-4, which charts the prices of the major fuel types used to make electricity for the last 11 years, shows that average annual input fuel prices increased in 2010. The price of natural gas remained at nominal values similar to those in 2000, while the price of oil has increased to nominal values similar to those in 2007. From their 2009 levels, in 2010, average annual prices have increased by about 9% for natural gas, 29% for No. 6 oil (1%), and 30% for No. 2 oil.[100] Coal prices have increased by about 27% over this time period.

[100] The power industry uses several types of fuel oils to generate electricity. No. 2 oil—also referred to as distillate fuel oil, light fuel oil, or diesel fuel oil—is distilled from crude oil. Among other uses, it is used as a backup fuel for peaking power plants. No. 6 oil is referred to as residual fuel oil or heavy fuel oil. It is what remains of the crude oil after gasoline and the distillate fuel oils are extracted. No. 6 oil is used by oil-burning power plants. No. 6 oil (1%) refers to the percentage of sulfur in the oil.

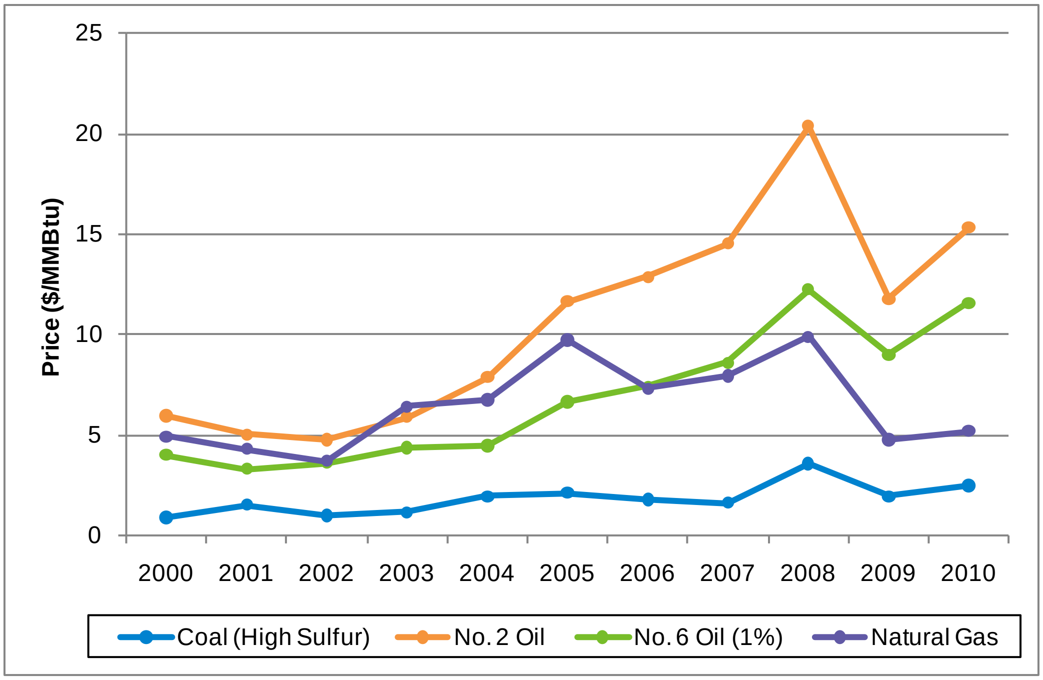

Figure 3-4: Average annual fuel prices for selected input fuels, 2000 to 2010.

Sources: Natural gas price information was provided by the Intercontinental Exchange, Inc. (ICE); http://www.theice.com. Coal and oil prices were provided by Argus Media; http://www.argusmedia.com/pages/StaticPage.aspx?tname=Argus+Home&pname=What%27s+New.

The magnitude of the price difference between input fuels varied over the most recent two-year period, as shown in Figure 3-5. The relationship between the price of No. 6 fuel and natural gas is important in New England because many older resources in New England burn No. 6 oil, while virtually all resources built since 1999 burn natural gas. The relationship between these two fuel prices determines how often each type of resource operates. In January 2009, natural gas was 1% more expensive than No. 6 oil. In February 2009, however, natural gas became the cheaper of the two fuels, and remained so through the end of 2010. As Figure 3-4 shows, the current large difference between natural gas prices and oil prices is unusual. The high cost of No. 6 oil has resulted in the ISO seldom running the region’s oil units for energy, and when they are needed for reliability, creating large NCPC payments (see Section 2.3.1).

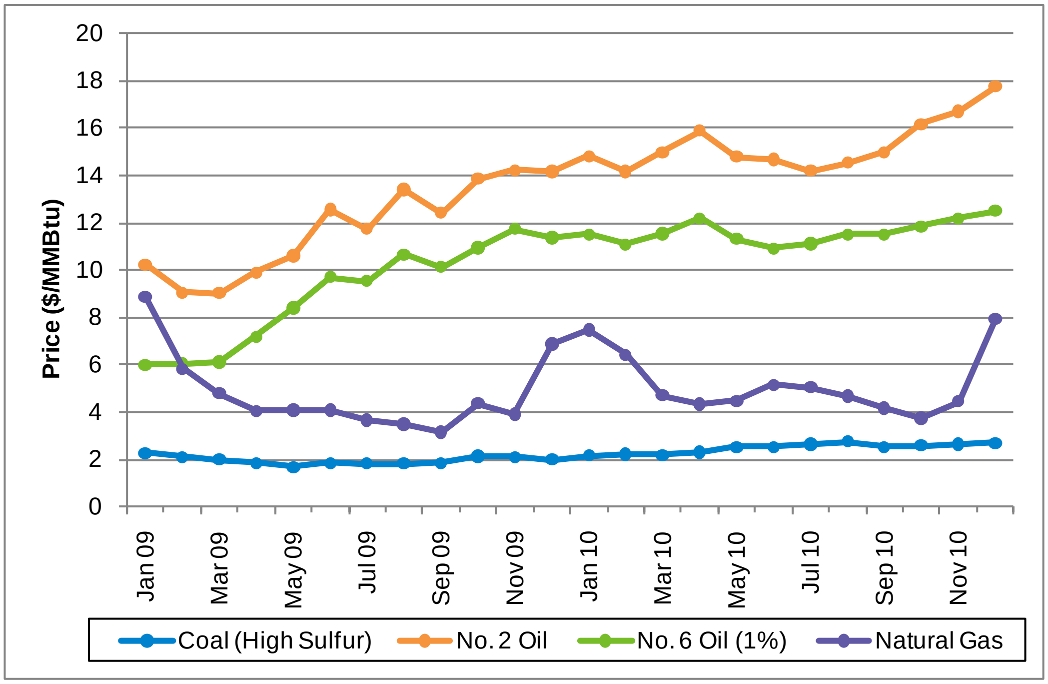

Figure 3-5: Average monthly fuel prices for selected input fuels, 2009 and 2010.

Sources: Natural gas price information was provided by the Intercontinental Exchange, Inc. (ICE); http://www.theice.com. Coal and oil prices were provided by Argus Media; http://www.argusmedia.com/pages/StaticPage.aspx?tname=Argus+Home&pname=What%27s+New/

3.1.3 Market Competiveness Conclusions

The QWLI results, the close correlation between natural gas and electricity prices, and the low levels of market concentration lead the IMM to conclude that market prices in 2010 were consistent with prices expected when resource owners offer at their short-run variable costs.

3.2 All-in Cost

The all-in wholesale electricity cost is an estimate of the total wholesale market cost of electric energy (in $/MWh).[101] The *all-in* cost value includes all wholesale market payments exclusive of transmission: the cost of electric energy, forward reserves, regulation, capacity reliability commitments, and FERC-approved Reliability Cost-of-Service Agreements (Reliability Agreements). The all-in cost of wholesale electricity rose from about $7.5 billion in 2009 to about $8.5 billion in 2010, an increase of 12%, or from $59.30/MWh in 2009 to $65.60/MWh in 2010, a 10% increase. Figure 3-6 shows the average annual all-in wholesale electricity cost and natural gas prices for 2008 through 2010.

[101] The all-in cost metric includes costs allocated to both wholesale load obligations and network load. The energy portion of the all-in cost is a zonal load-weighted average of zonal prices. This is a slightly different concept than the system load-weighted average Hub price reported in the fuel-adjusted price analysis shown in Section 3.4.2, and the simple average of wholesale prices at the Hub. This analysis uses this metric of zonal load-weighted averages of zonal prices because it better represents the prices paid by load. The ISO publishes a separate wholesale load cost metric that includes only costs allocated to real-time load obligations.

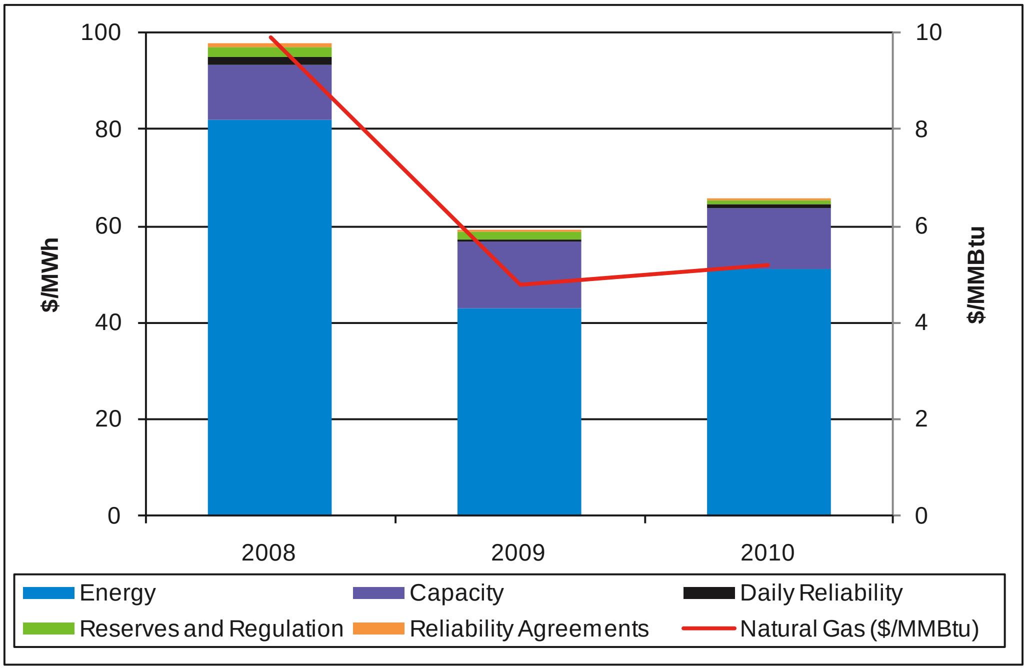

Figure 3-6: All-in cost for electricity.

Notes: The daily reliability and Reliability Agreement costs are allocated systemwide to enable a systemwide rate to be calculated. These costs actually are allocated to the load zone in which they occur. MMBtu stands for millions of British thermal units, a measure of the amount of heat energy in natural gas.

Source: Natural gas price information provided by the Intercontinental Exchange, Inc. (ICE); http://www.theice.com.

The energy component, driven by higher fuel prices and increased loads, rose 19%, from $42.89/MWh in 2009 to $50.98/MWh in 2010. Daily reliability costs, caused in part by the outage of a large unit in the second half of the year, rose from $0.44/MWh in 2009 to $0.73/MWh in 2010, a 67% increase. The reserves and regulation component decreased 19%; the capacity component, 9%; and the Reliability Agreements component, 87%. Reliability Agreements no longer applied after June 1, 2010.

3.3 Day-Ahead Energy Market

This section presents information about prices, demand, and supply in the day-ahead market in 2010.

3.3.1 Day-Ahead Prices

Table 3-3 shows day-ahead electricity prices for the Hub and the difference between the Hub price and prices for each of the eight New England load zones for 2009 and 2010. The average day-ahead Hub price in 2010 was higher than in 2009 for the reasons discussed above. During 2010, average day-ahead zonal prices did not vary more than about $0.87/MWh from the Hub, with the exception of Maine and Connecticut. The differences in prices are primarily caused by transmission losses, rather than congestion. Average LMPs in Maine were about $2.19/MWh lower than the Hub, largely because of the transmission losses that occur when power travels from Maine to the load in southern New England. The average CT load zone LMPs were $1.87/MWh greater than the average Hub price caused by transmission losses and some congestion. These results are similar to results in 2009. In 2009, the difference in the average price between the Maine and Connecticut load zones was $3.14/MWh. In 2010, it was $4.06/MWh, reflecting the increase in overall price levels.

Table 3-3
Simple Average Day-Ahead Hub Prices
and Load-Zone Differences for 2009 and 2010 ($/MWh)

Location/Load Zone	2009	2010
Hub	$41.54	$48.89
Maine	−$1.93	−$2.19
New Hampshire	−$0.67	−$0.87
Vermont	$0.05	$0.68
Connecticut	$1.21	$1.87
Rhode Island	−$0.39	−$0.79
SEMA	$0.17	−$0.56
WCMA	$0.36	$0.63
NEMA	−$0.09	−$0.67

3.3.2 Day-Ahead Demand for Electric Energy

Figure 3-7 shows the total percentage of day-ahead cleared demand by category. Fixed demand has continued to increase slightly, from 56% as a percentage of total cleared demand in 2008, to 61% in 2009, and to 63% in 2010. Virtual demand and price-sensitive demand (see Section 2.1.2) have decreased as a percentage of total demand, while exports have increased slightly.

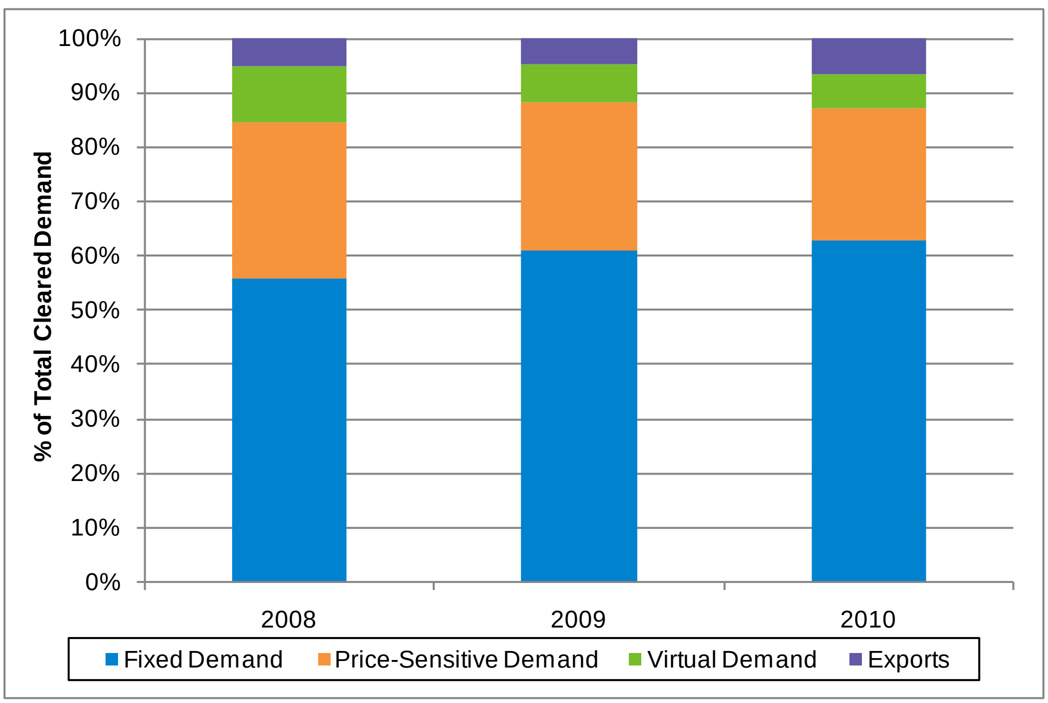

Figure 3-7: Day-ahead demand by category.

3.3.3 Day-Ahead Supply of Electric Energy

Figure 3-8 shows the percentage of cleared day-ahead self-scheduled and price-sensitive supply offers, virtual supply offers, and imports for 2008, 2009, and 2010. Day-ahead self-schedules were at about the same level as last year, accounting for over 60% of day-ahead supply in 2010. Cleared economic supply has increased from 22% in 2009 to 26% this year. In 2010, the quantity of virtual supply offers was smaller than in 2009. As discussed in more detail in Section 3.4.1, this was caused in large part by average real-time prices that exceeded average day-ahead prices, making virtual supply transactions less attractive and high levels of NCPC being allocated to deviations. While a large percentage of both day-ahead supply and demand was fixed, or price insensitive, sufficient quantities of price-sensitive supply and demand allowed for efficient price formation in the day-ahead market.

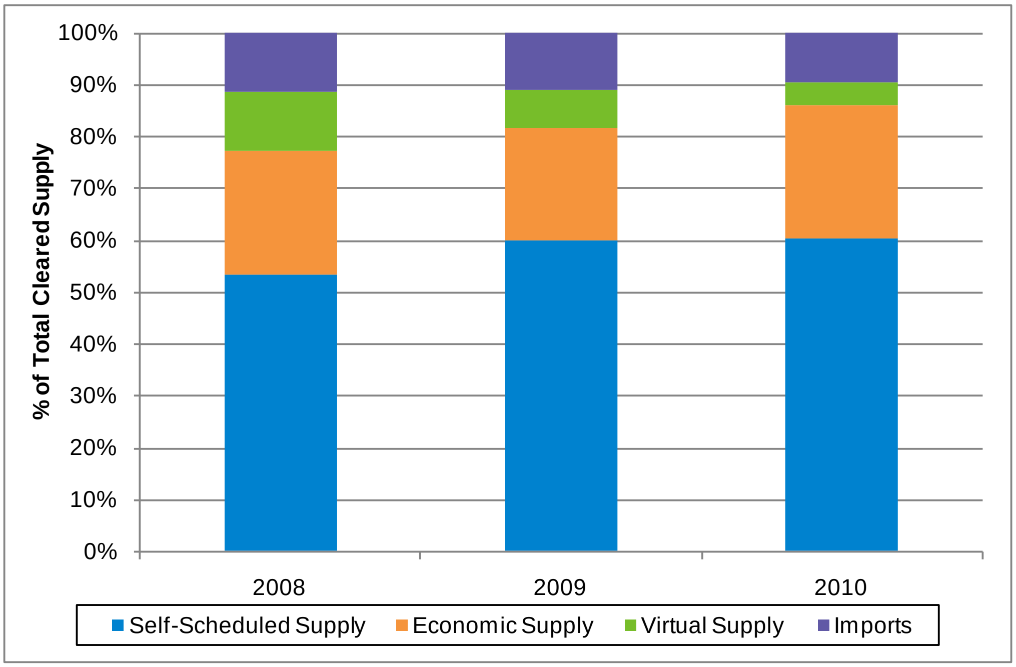

Figure 3-8: Day-ahead supply as a percentage of total cleared supply.

3.4 Real-Time Energy Market

This section presents the results of the Real-Time Energy Market in 2010. It reviews prices, the demand for electricity, total generation output, imports and exports, and real-time reserves, and it compares day-ahead and real-time prices.

3.4.1 Real-Time Prices

Figure 3-9 shows average monthly real-time Hub prices for New England over the past three years. The figure shows that prices during 2008 were high through August and then dropped. In 2010, prices were generally higher than in 2009. These higher prices throughout the summer months are attributable to warm weather; higher input fuel prices; and the extended, unexpected outage of a large resource from May to December.

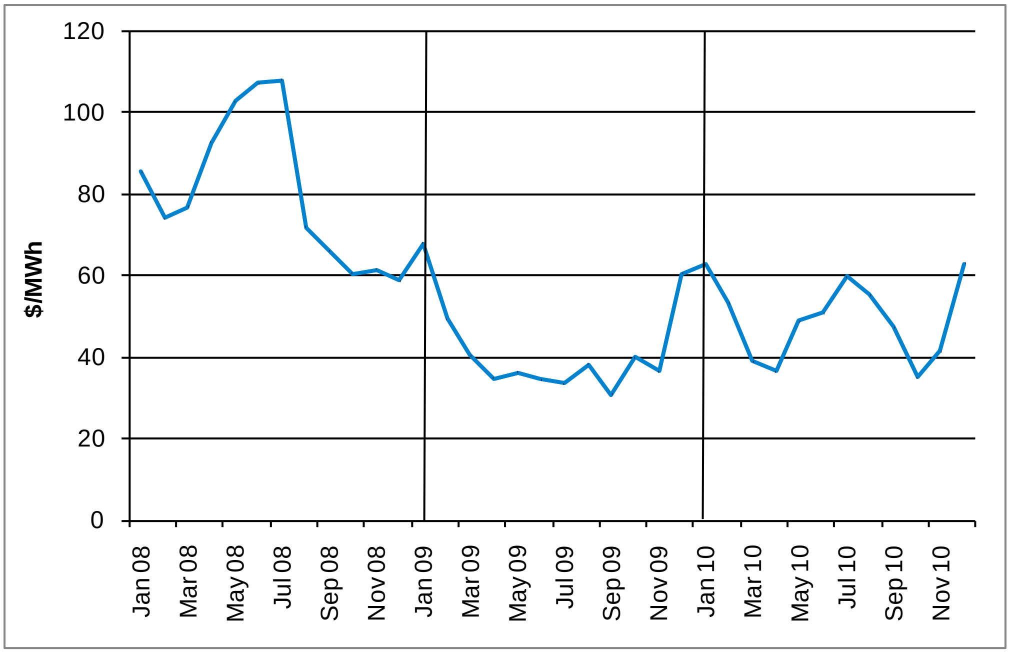

Figure 3-9: Average monthly real-time Hub prices, 2008 to 2010 ($/MWh).

Table 3-4 shows real-time electricity prices for the Hub and the difference between the Hub and each of the eight New England zones for 2009 and 2010. The relationship of prices between the regions was the same in 2010 as in 2009. The average Hub price during 2010 was higher than during 2009. During 2010, average real-time zonal prices did not vary more than about $0.86/MWh from the Hub, with the exception of Maine and Connecticut. The differences in prices were primarily caused by transmission losses rather than congestion. Average LMPs in Maine were about $2.49/MWh lower than the Hub, largely because of the transmission losses that occur when power travels from Maine to the load in southern New England. The average CT load zone LMPs were $1.21/MWh greater than the average Hub price as a result of transmission losses and some congestion.

Table 3-4
Simple Average Real-Time Hub Prices and Load-Zone Differences for 2009 and 2010 ($/MWh)

Location/Load Zone	2009	2010
Hub	$42.02	$49.56
Maine	−$2.02	−$2.49
New Hampshire	−$0.67	−$0.86
Vermont	$0.06	$0.34
Connecticut	$0.90	$1.21
Rhode Island	−$0.43	−$0.69
SEMA	$0.04	−$0.27
WCMA	$0.34	$0.51
NEMA	−$0.22	−$0.32

3.4.2 Fuel-Adjusted Prices

Figure 3-10 shows the annual average load-weighted Hub prices and the annual average load-weighted fuel-adjusted electric energy prices for 2000 to 2010.[102] The IMM developed the fuel-adjusted electric energy price to track the relationship between changes in input fuel prices and electric energy prices. While informative, it is subject to limitations because it does not account for any changes in dispatch caused by changes in relative fuel prices, the mix of resources, and load. The 2010 fuel-adjusted prices are consistent with the prices in previous years, indicating that fuel prices continue to drive electricity prices, consistent with expectations of a competitive market.

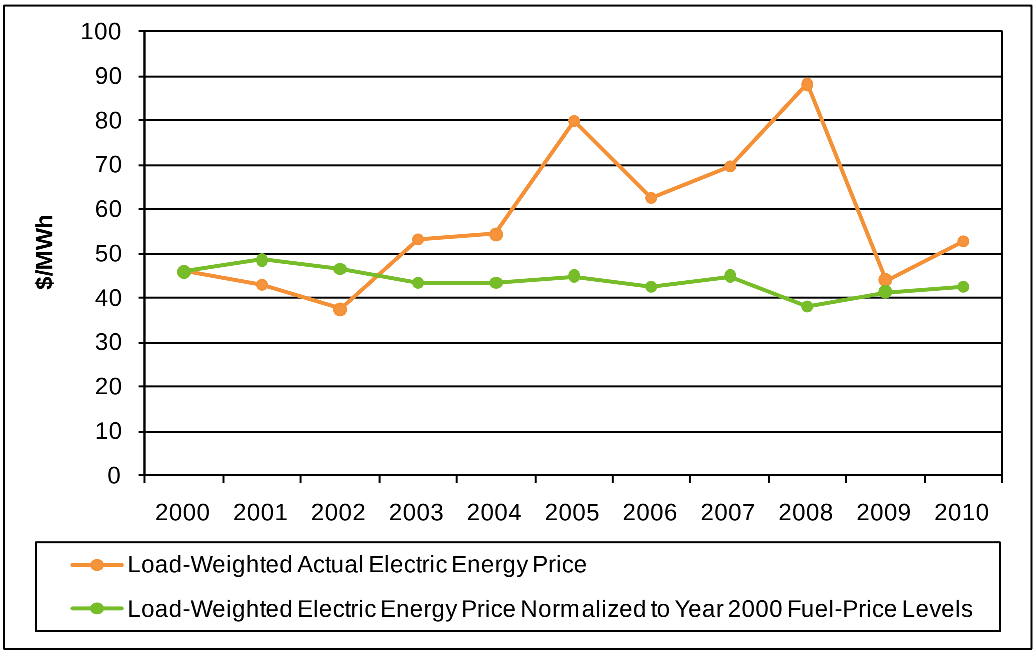

Figure 3-10: Actual and fuel-adjusted average real-time electric energy prices, 2000 to 2010.

Note: Prices are system load-weighted average Hub prices.

3.4.3 Difference between Day-Ahead and Real-Time Prices

As Table 3-5 shows, the average day-ahead and real-time energy prices at the New England Hub in 2010 were $48.89/MWh and $49.56/MWh, respectively. The average day-ahead to real-time price differential has been declining. In 2005, the annual average difference was 2.4% (day ahead greater than real time). In mid-2009, the relationship switched, and real-time prices averaged 1.15% greater than day-ahead prices (i.e., a −1.15% day-ahead to real-time price difference). This relationship continued in 2010 with an average day-ahead to real-time price differential of −1.37%.

[102] Fuel-adjusted prices are calculated by adjusting the price of electricity in each hour of the year 2000 by the change in the price of the fuel used by the marginal unit for the adjustment year. Average monthly fuel indices are used to make the adjustment.

Table 3-5
2010 Annual and Quarterly
Day-Ahead and Real-Time Hub Prices ($/MWh)

	Annual	Q1	Q2	Q3	Q4
Day ahead	$48.89	$50.45	$43.27	$53.33	$48.49
Real time	$49.56	$51.71	$45.55	$54.26	$46.70

3.4.4 Virtual Transactions

Over the past year, the volume of submitted and cleared virtual supply offers has decreased and the volume of virtual demand bids has stayed flat, despite real-time prices that exceeded day-ahead prices on average for the year. Overall, a number of participants have reduced their volume of virtual trading activity or have changed their bidding strategies. Virtual supply offer volumes recovered somewhat in the fourth quarter, the result of a positive day-ahead premium overall in the quarter. This behavior is broadly consistent with the following:

- Through the third quarter, changes in the day-ahead/real-time price relationship have reduced the opportunities for virtual supply in the day-ahead market. To some extent, this turned around in the fourth quarter.
- The risk associated with taking virtual positions has increased given, the increased volatility of real-time prices, but more importantly, the magnitude and uncertainty of real-time NCPC.
- The transaction costs associated with taking virtual positions are high and uncertain. Over the past several months, the total allocated NCPC charges have exceeded the total gross profits from the virtual positions.

Those virtual traders who have remained in the market have added estimates of the per-megawatt-hour allocation of NCPC to their bids and offers. As a result, less virtual supply and demand economically clears in the day-ahead market, and the resulting price spread of several dollars per megawatt-hour effectively limits day-ahead and real-time price convergence.

3.4.5 Virtual Supply Offers

The IMM reviewed submitted and cleared virtual supply offers from January 2009 through December 2010. Figure 3-11 shows submitted and cleared virtual supply offer volumes. Submitted virtual supply offers have decreased 27% from January through December 2010 compared with January through December 2009. A number of speculative participants have stopped submitting virtual supply offers or have changed their bidding strategies.

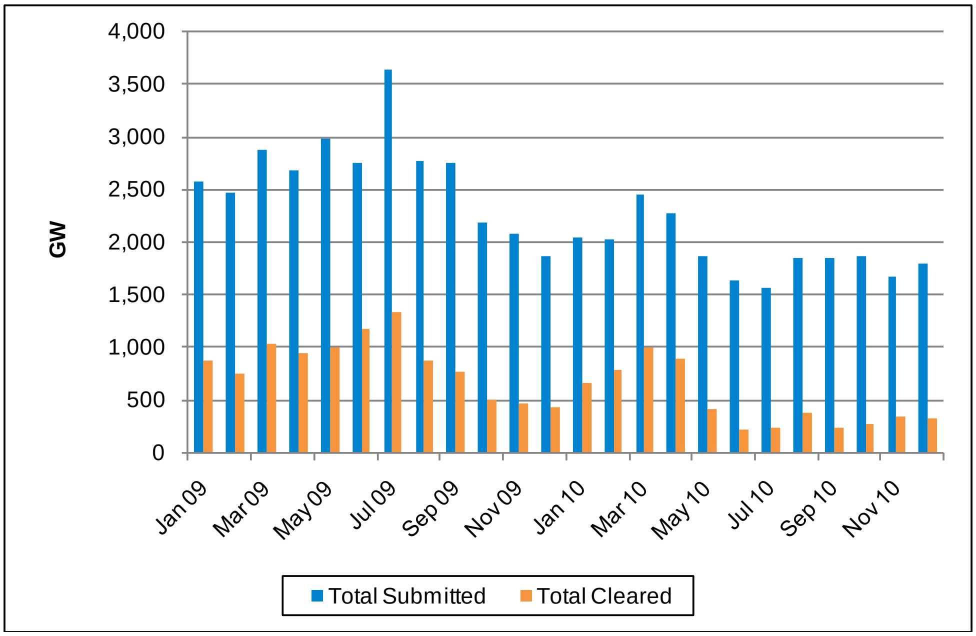

Figure 3-11: Submitted and cleared virtual supply offer volumes, January 2009 to December 2010.

3.4.6 Virtual Demand Bids

Figure 3-12 presents submitted and cleared virtual demand bids for 2009 and 2010. The volatility in the difference between the day-ahead and real-time price also affected the submission of virtual demand bids for some participants. While a number of market participants reduced the volume of submitted virtual demand bids, other participants have increased volumes.

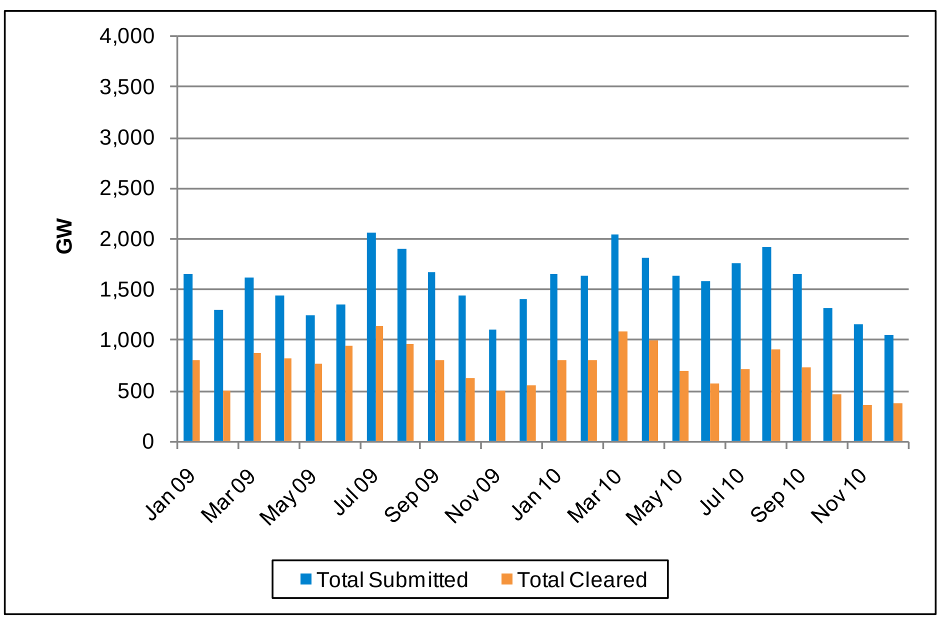

Figure 3-12: Submitted and cleared virtual demand bids, January 2009 to December 2010.

3.4.7 NCPC Charges to Virtual Transactions

The IMM has observed that the total amount of NCPC charged to virtual transactions has been remarkably high relative to the overall profitability of the positions taken. Figure 3-13 and Figure 3-14 present average monthly gross and net profits (after adding in the NCPC charged to virtual transactions) for virtual supply offers and virtual demand bids. The willingness of a participant to take virtual positions will be greatly reduced by the high transaction costs imposed in the form of real-time NCPC charges.

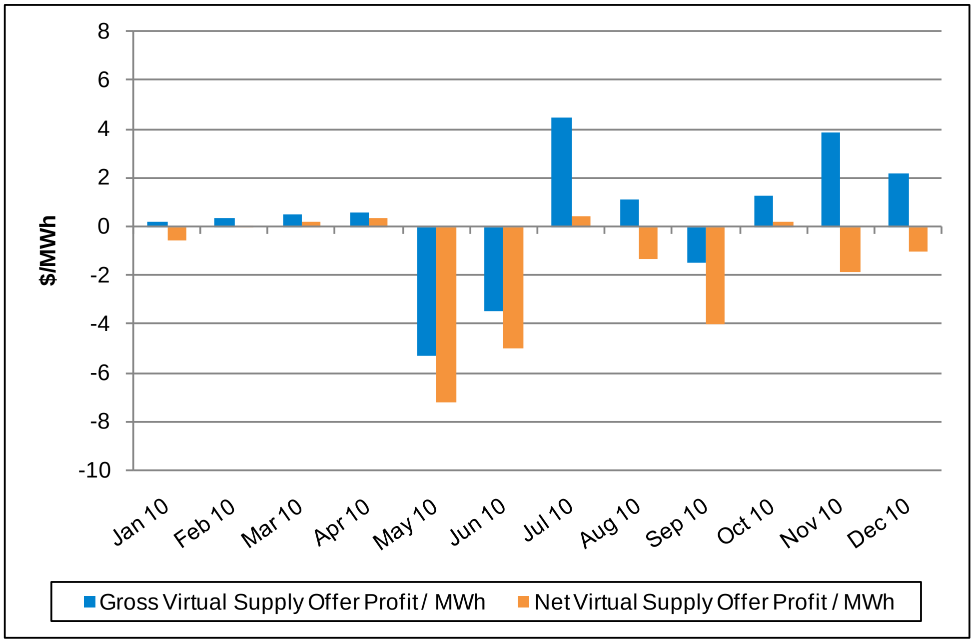

Figure 3-13: Gross and net profits for day-ahead and real-time virtual supply offers, January to December, 2010.

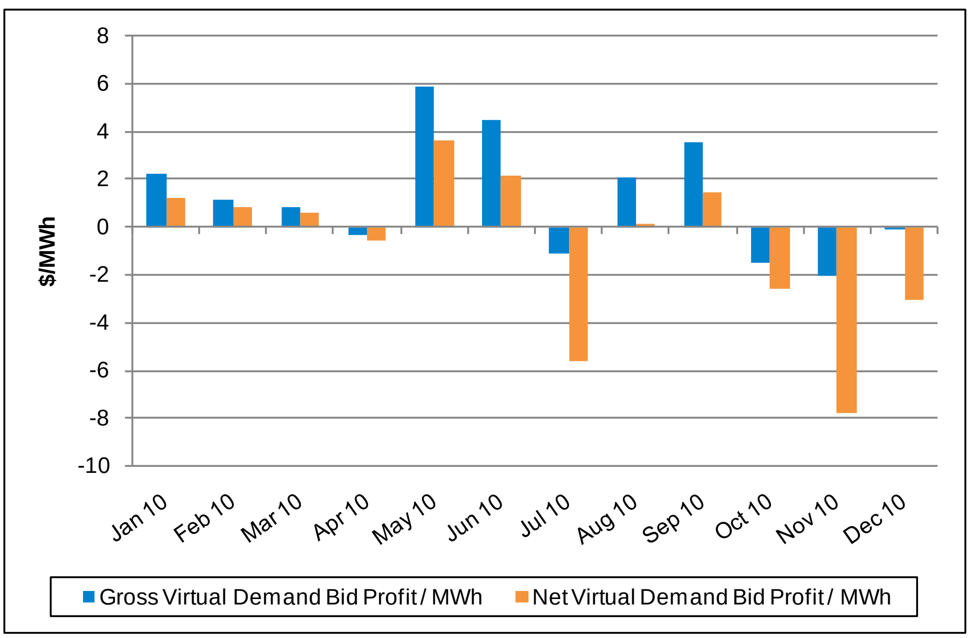

Figure 3-14: Gross and net profits for day-ahead and real-time virtual demand bids, January to December, 2010.

During the year, the profitability of virtual positions totaled $14 million. The total allocation of real-time NCPC charges to these positions totaled $22.2 million. Net of real-time NCPC-related transaction costs, virtual positions realized a total loss of $8.1 million. See Table 3-6.

Table 3-6
Net Revenues and Real-Time NCPC Charges to Virtual Transactions by Quarter, January to December 2010

Virtual Instrument	Revenues and Charges	Q1	Q2	Q3	Q4	2010
Demand	Net revenue (before NCPC charges)	3,619,465	6,364,014	3,671,866	−1,440,879	12,214,466
	Allocated real-time NCPC charges	−1,311,264	−2,949,007	−6,159,789	−3,681,287	−14,101,348
	Revenue net of real-time NCPC charges	***2,308,201***	***3,415,007***	***−2,487,923***	***−5,122,166***	***−1,886,882***
Supply	Net revenue (before NCPC charges)	866,691	−2,464,206	1,106,428	2,365,980	1,874,894
	Allocated real-time NCPC charges	−1,019,648	−1,315,325	−2,465,197	−3,296,519	−8,096,690
	Revenue net of real-time NCPC charges	***-152,957***	***-3,779,531***	***−1,358,769***	***−930,539***	***−6,221,796***
Total	Net revenue (before NCPC charges)	4,486,157	3,899,808	4,778,294	925,101	14,089,359
	Allocated real-time NCPC charges	−2,330,912	−4,264,333	−8,624,986	−6,977,806	−22,198,037
	Revenue net of real-time NCPC charges	***2,155,245***	***−364,525***	***−3,846,692***	***−6,052,705***	***−8,108,678***

Virtual transactions in the Day-Ahead Energy Market play an important function, generally increasing liquidity, improving commitment, and limiting the exercise of market power. Virtual positions act to converge the day-ahead and real-time prices, and, in so doing, reduce the need for supplemental commitments in real time and the uplift costs associated with these positions. The imposition of a high level of transaction costs may threaten the viability of virtual transactions in the Day-Ahead Energy Market, with potentially serious implications for the performance of the market. The IMM has recommended that the ISO revise the market rules so that real-time NCPC charges are not allocated to virtual transactions. The ISO presently is evaluating this recommendation.

3.4.8 Day-Ahead Demand Compared with Real-Time Demand

Beginning in the latter half of 2009, the IMM reported a decline in the percentage of real-time loads that cleared in the day-ahead market compared with historic levels.[103] The decline became more pronounced through the summer of 2010. The IMM opened an investigation of this change to

[103] *2010 Second Quarter Quarterly Markets Report* (August 24, 2010), http://www.iso-ne.com/markets/mkt_anlys_rpts/qtrly_mktops_rpts/2010/2010_q2_imm_market_report_filing_dmeast_12810119_1.PDF. *2010 Third Quarter Quarterly Markets Report* (November 16, 2010), http://www.iso-ne.com/markets/mkt_anlys_rpts/qtrly_mktops_rpts/2010/imm_qmr3_final.pdf. *2010 Fourth Quarter Quarterly Markets Report* (February 22, 2011), http://www.iso-ne.com/markets/mkt_anlys_rpts/qtrly_mktops_rpts/2010/imm_qmr4_%202010_final.pdf.

determine whether it was the result of anticompetitive behavior. The IMM has completed its review of day-ahead demand clearing as a percentage of real-time load and has found no evidence of market manipulation or anticompetitive behavior.

In summary, the IMM has found the following:

- Neither the average amount nor the standard deviation of load clearing in the day-ahead market as a percentage of real-time load has changed materially.
- The principal change in behavior highlighted by the metric presented in the previous reports and that prompted the analysis is the steady decline in the volume of virtual supply clearing in the day-ahead market.
- The amount of load clearing the day-ahead market is consistent with prevailing market conditions.

The IMM has developed a revised metric that looks at the *net* day-ahead cleared demand as a percentage of real-time load (i.e., the net load that physical generation and imports are scheduled to meet in the day-ahead market). This metric provides more insight into how the amount of demand clearing in the day-ahead markets affects the amount and frequency of balancing commitments in the Reserve Adequacy Analysis (RAA) and, consequently, uplift charges.

The revised metric measures the energy purchased in the day-ahead market as a percentage of actual energy consumption in New England. It is calculated as follows:

Day-Ahead Demand Cleared as a Percentage of Real-Time Load =
(Fixed Demand + Price-Sensitive Demand + Virtual Bids – Virtual Offers)/
(Net Energy for Load).

Figure 3-15 shows the simple monthly averages of the revised metric for 2009 through 2010.

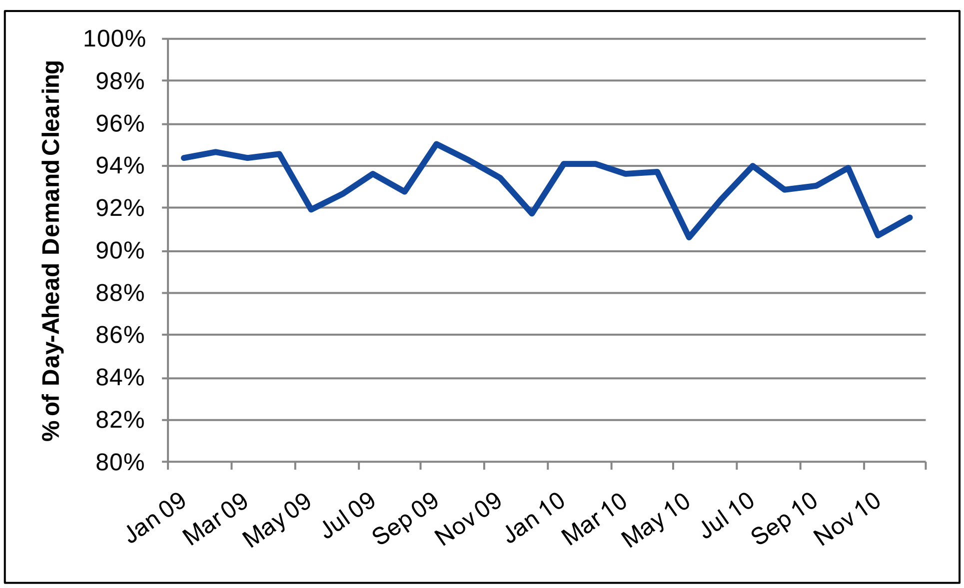

Figure 3-15: Day-ahead cleared demand as a percentage of real-time load, 2009 to 2010.

The IMM compared daily demand clearing during the May to December 2010 period (the "current period") with that in the May to December 2003–2009 time period (the 'historical period"). Figure 3-16 and Figure 3-17 present histograms depicting the daily observations of day-ahead demand clearing in the current period compared with the historical period. The analysis shows that the percentage of demand clearing in the Day-Ahead Energy Market as a percentage of real-time consumption has not changed significantly.

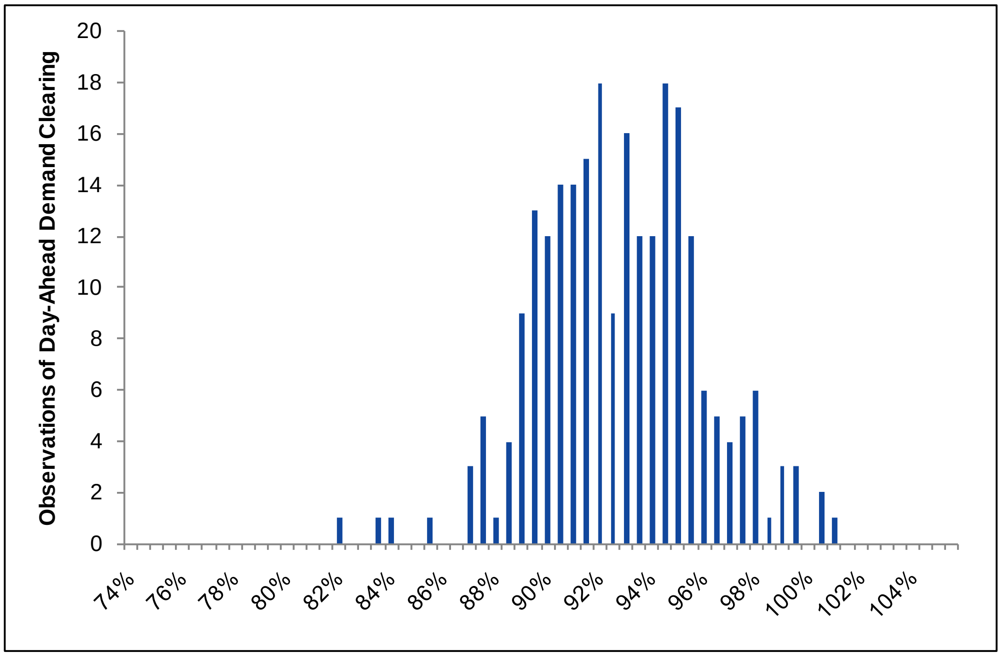

Figure 3-16: Histogram of day-ahead demand clearing, current period, May to December, 2010.

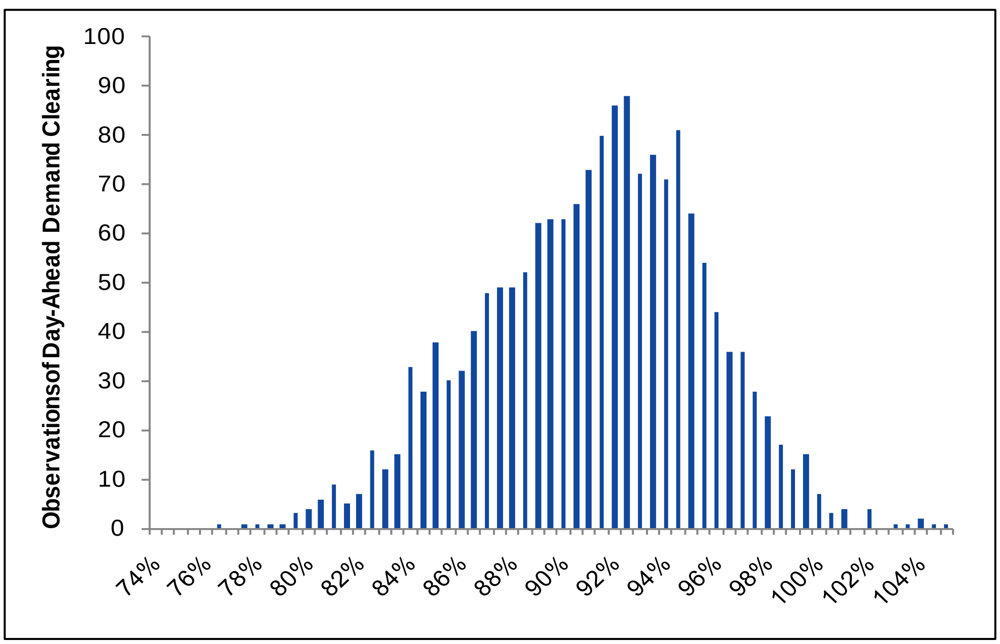

Figure 3-17: Histogram of day-ahead demand clearing, historical period, May to December, 2003 to 2009.

Additionally, the IMM reviewed the bidding strategies of the top 10 load-serving entities and the LSEs with the largest real-time deviations relative to the size of the overall real-time demand. The percentage of their fixed and price-sensitive demand bids into the day-ahead market has been remarkably consistent. The IMM also contacted several LSEs to discuss their strategies. The LSEs reported that, in general, the amount of load purchased day-ahead depends on the characteristics of the portfolio of customers and supply-asset holdings, both physical and financial (e.g., options, swaps, etc.). Most LSEs reported that at least some of their position was naturally hedged against real-time prices, thus not bid day-ahead.

3.4.9 Real-Time Demand

Table 3-7 shows that the actual demand for electricity increased by about 3% from 2009 to 2010, while weather-normalized demand increased by about 1%.[104] The increase in electric energy consumption from 2009 to 2010 is consistent with the overall increase in economic activity.

Table 3-7
Annual and Peak Electric Energy Statistics, 2008 to 2010

	2008	2009	2010	% Change 2009 to 2010
Annual NEL (GWh)[a]	131,754	126,839	130,771	3.1%
Normalized NEL (GWh)[a]	131,215	128,268	129,910	1.3%
Recorded peak demand (MW)	26,111	25,100	27,102	8.0%
Normalized peak demand (MW)	27,525	27,220	27,075	−0.5%

(a) "GWh stands for gigawatt-hours.

3.4.10 Real-Time Supply

This section presents data on real-time summer capacity, generation by fuel type, self-scheduled generation, and the results of a marginal-unit analysis.

3.4.10.1 Summer Capacity

Figure 3-18 shows summer capacity by fuel type for 2010.[105] In 2010, gas-fired generators made up 24% of installed capacity, oil-fired generators made up 14% of installed capacity, and units that burn both gas and oil made up 25% of installed capacity. Environmental restrictions on emissions from burning oil can limit the total number of hours per year a generator can operate on oil. Many dual-fueled generators capable of burning either oil or natural gas operate primarily on natural gas.

[104] *Weather-normalized* results are those that would have been observed if the weather were the same as the long-term average.

[105] The data come from the 2010 *Capacity, Energy, Load, and Tansmission (CELT) Report* (May 18, 2010). Detailed information about generating capacity is available in the ISO's CELT reports, http://www.iso-ne.com/trans/celt/report/index.html.

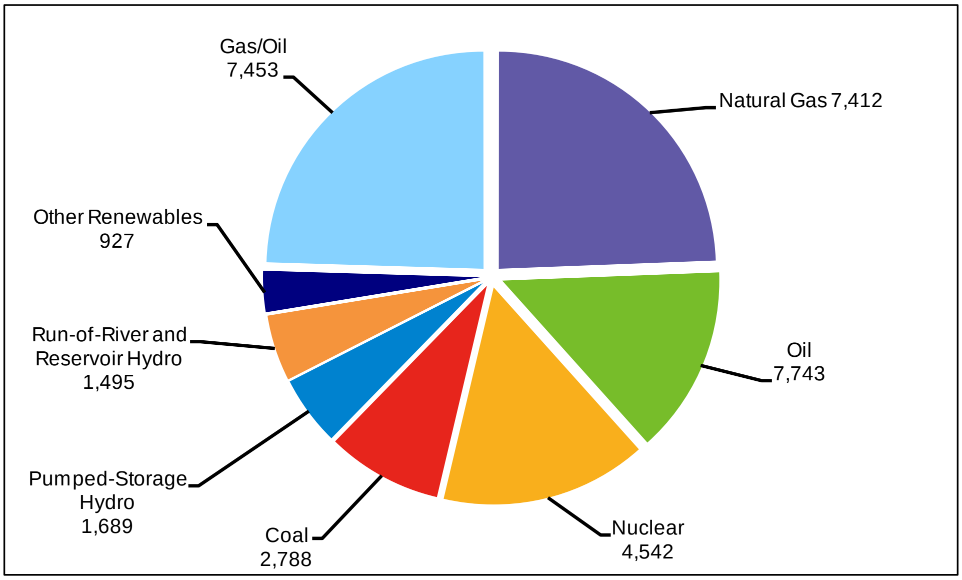

Figure 3-18: System summer capacity by fuel type, 2010 (MW).

The total 2010 generation claimed for capability was 30,380 MW—down 1,238 MW from the 2009 level of 31,619 MW.

3.4.10.2 Generation by Fuel Type

Figure 3-19 shows actual generation by fuel type as a percentage of total generation for 2009 and 2010. The figure shows the fuels used to generate electric power, which differ from the capacity fuel mix shown above and the marginal unit by fuel type (discussed below in Section 3.4.10.6 and shown in Figure 3-24). The percentage of total electric energy generated by gas-fired and gas- and oil-fired plants in New England was about 45.5% in 2010. Nationwide, about 23% of electric energy is produced by power plants fueled by natural gas.[106]

[106] Energy Information Administration, *Electricity Generation* (Washington, DC: US Department of Energy, August 2010); available at http://tonto.eia.doe.gov/energyexplained/index.cfm?page=electricity_in_the_united_states#tab2 (accessed February 14, 2011).

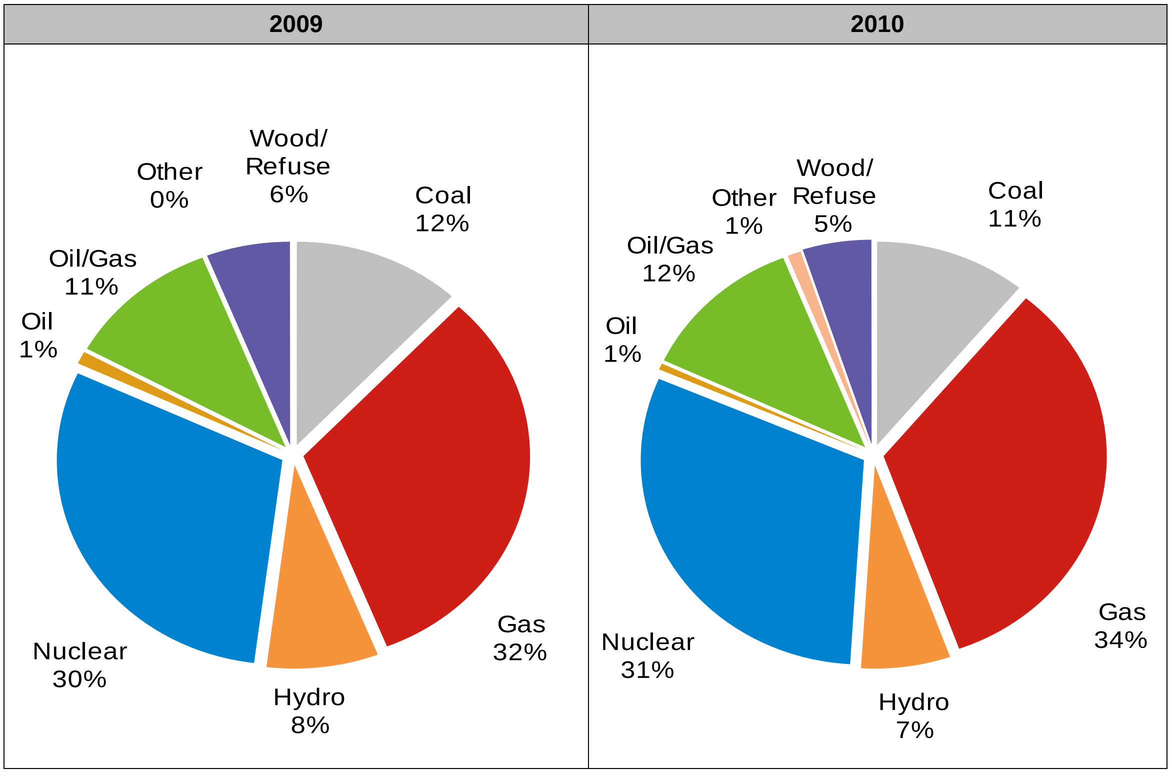

Figure 3-19: New England generation by fuel type, 2009 and 2010.

NOTE: "Other" fuels include steam, wind, solar, and methane.

3.4.10.3 Spark Spreads

A *spark spread* is a measure of the gross margin (electric energy revenues minus fuel costs) from converting fuel to electricity based on the wholesale price of electricity and the cost of producing electricity with a given fuel and technology. Figure 3-20 presents quarterly estimated natural gas spark spreads based on the simple quarterly average real-time Hub price for on-peak hours from January 2008 through December 2010 and the fuel costs of a typical combined-cycle gas turbine (CCGT) in New England, using the Algonquin gas price; a heat rate of 7,800 Btu/kWh; and 100% availability.[107] The results show that, on average, gas units earned a positive gross margin in 2010, with the quarterly average spark spread lying between $6.29/MWh and $30.49/MWh.

[107] The Algonquin Gas Transmission is a regional interstate natural gas pipeline system that transports natural gas from pipeline interconnects in New Jersey and southeastern New England to major markets in New England.

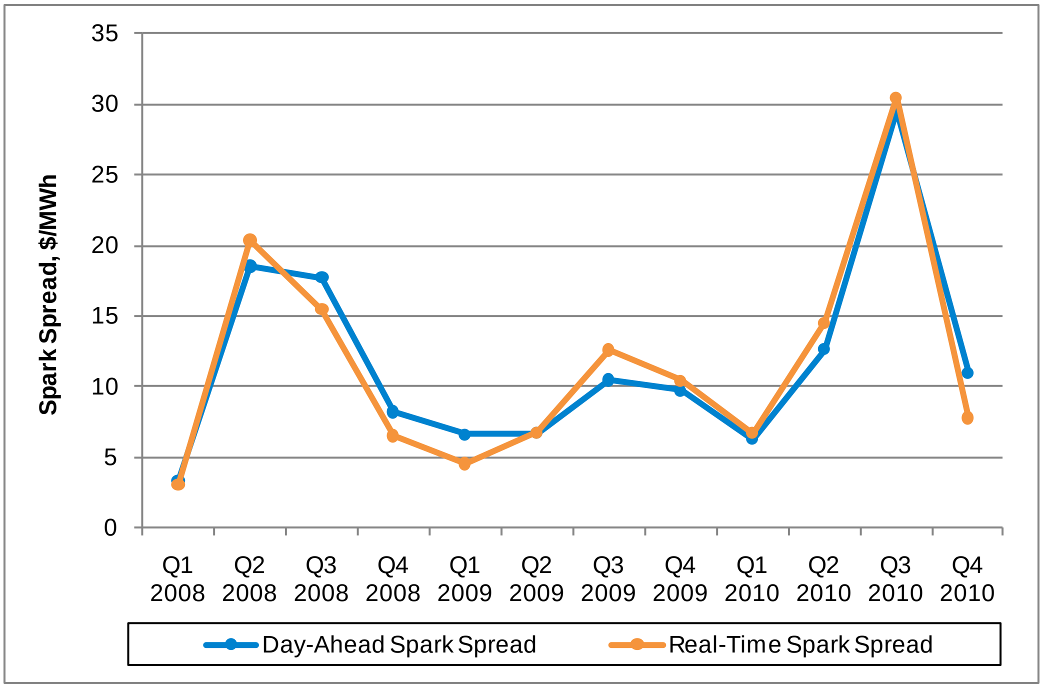

Figure 3-20: Quarterly spark spreads for on-peak hours, 2008 to 2010.

In 2010, the typical gas unit presented in this analysis earned a gross margin of approximately $14.91/MWh in day ahead and $14.92/MWh in real time, which represents an increase of 77% for day ahead and 73% for real time compared with 2009, and an increase of 24% for day ahead and 30% for real time compared with 2008.[108] The overall increase in 2010 is the result of higher loads in the summer months and the need to run more expensive units to operate, which resulted in oil units setting prices (at high levels) more frequently.

3.4.10.4 Hydroelectric Output

Yearly hydroelectric production in 2010 was lower than the last two years (20% lower than 2008 and 17% lower than 2009) and closer to average historic levels—only 8% over the average hydro production from 2000 to 2007.[109] Over the course of the year, hydroelectric resources produced 7% of total system generation.

Figure 3-21 shows hydroelectric production for New England by seasons. The data are organized into seasonal averages for 2003 to 2007, 2008, 2009, and 2010.[110] The data show that 2010 hydroelectric production decreased for all seasons except winter compared with 2009 averages.

[108] This is an idealized representation of the gross margins to a combined-cycle unit. An evaluation of revenues earned by any particular resource should take into account all unit-specific operating characteristics (e.g., minimum run time, ramp rates, economic minimum, and heat rate).

[109] Percentages are based on annual historical generation data reported by the ISO at http://www.iso-ne.com/markets/hstdata/rpts/net_eng_peak_load_sorc/index.html. Refer to Section 8.1 for additional information.

[110] For this analysis, seasons are defined as three-month periods: December through February, March through May, June through September, and October through November. Using this definition, the winter season includes December data from one year and the January and February data from the next year. Therefore, the output for December 2008 is included in the total output for winter 2009.

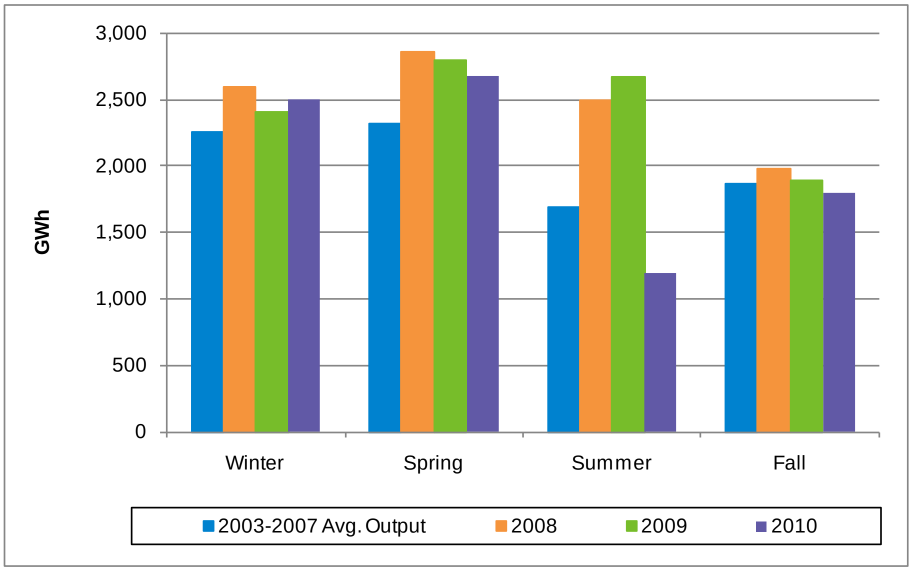

Figure 3-21: Historical hydroelectric energy production by season for New England, 2003 to 2007 average, 2008, 2009, and 2010 (GWh).

3.4.10.5 Self-Scheduled Generation

Figure 3-22 shows real-time self-scheduled generation as a percentage of total electric energy produced from 2008 through 2010. Self-scheduling is of interest because self-scheduled generators are willing to operate at any price and are not eligible to set clearing prices. Participants may choose to self-schedule their generators' output for a variety of reasons. For example, those with day-ahead generation obligations may self-schedule in real time to ensure that they meet their day-ahead obligations. Participants with fuel contracts that require them to take fuel also may self-schedule. In addition, participants may self-schedule resources to prevent the units from being cycled off overnight and then started up again the next day. In 2010, self-scheduled generation averaged 63% of total real-time energy, down from 66% in 2009.

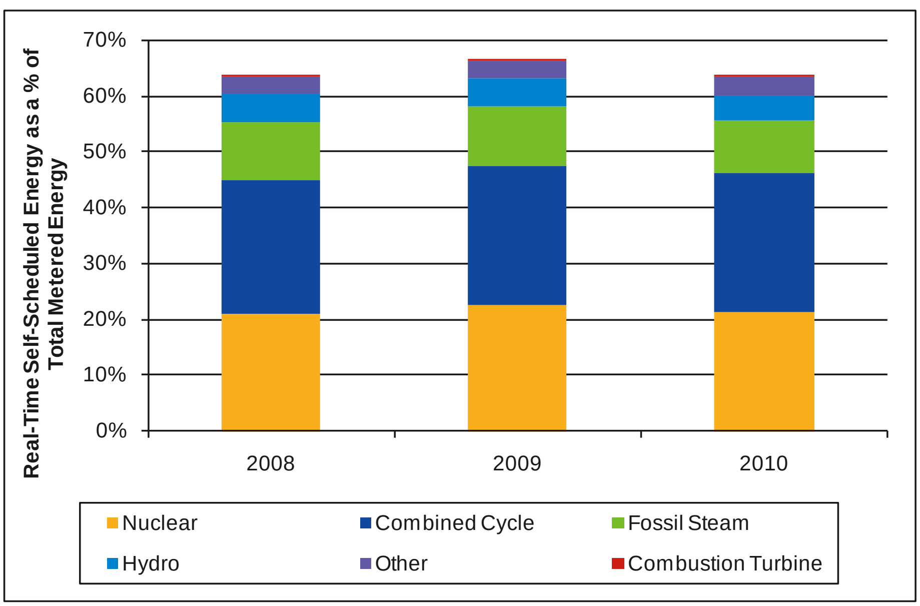

Figure 3-22: Total real-time self-scheduled electric energy as a percentage of total metered energy, 2008 to 2010.

Figure 3-23 shows total annual self-scheduled generation by technology type from 2008 to 2010. Combined-cycle resources comprised 39% of real-time self-scheduled generation, more than any other single technology type. Nuclear generators in New England have historically self-scheduled their generation; therefore, 100% of the metered energy generated by all nuclear plants is self-scheduled energy.

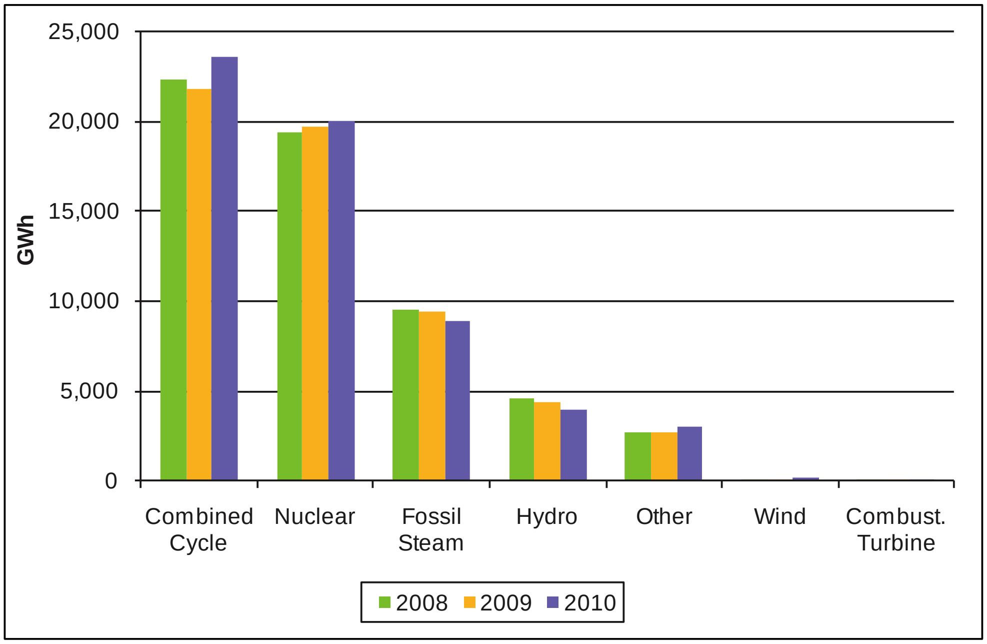

Figure 3-23: Real-time self-scheduled generation by technology type, 2008 to 2010.

3.4.10.6 Marginal Unit Analysis

In an LMP system, the price typically is set by the cost of the megawatt that would be dispatched to meet the next increment of load. This unit generally is referred to as the marginal unit. Because the price of electricity changes as the price of the marginal fuel changes, examining marginal units by fuel type helps to understand changes in electricity prices. During all pricing intervals, the system has one marginal unit classified as the *unconstrained* marginal unit. However, more than one marginal unit exists in intervals when transmission constraints are present. For example, during high loads, the interface between Connecticut and the rest of the New England power system becomes constrained, and generation in Connecticut is *dispatched up* to meet load, resulting in two marginal units, one on each side of the constrained interface.

Figure 3-24 shows the percentage of total pricing intervals during which each input fuel was marginal during unconstrained periods in 2010. The unconstrained intervals accounted for more than 64% of the pricing intervals. Natural gas was the fuel most frequently on the margin. The next-most-frequent fuels on the margin were coal and pumped-storage generation and demand. When considering both unconstrained and constrained periods, natural gas was the marginal fuel during more than 71% of the pricing intervals.

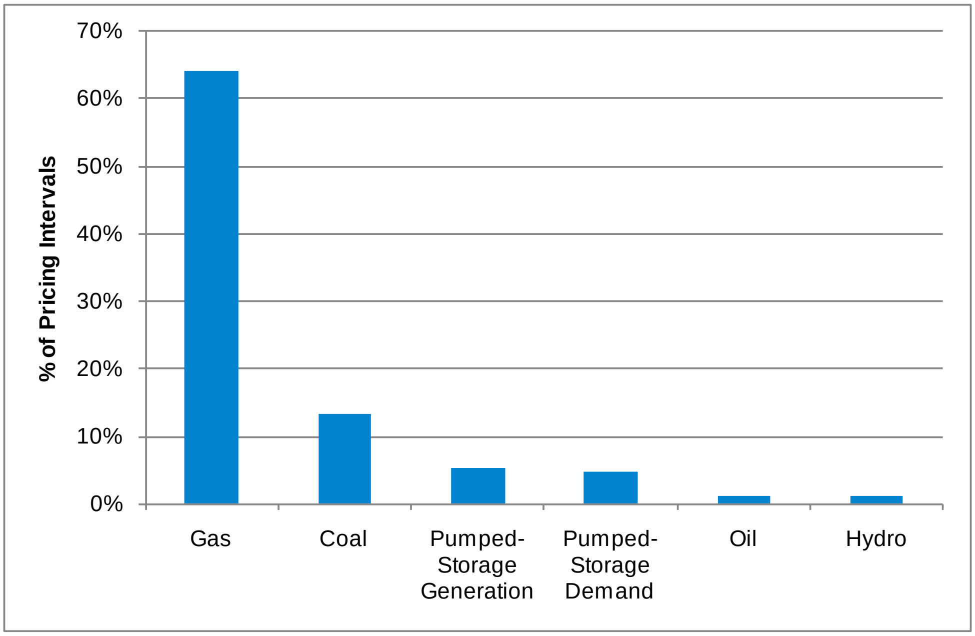

Figure 3-24: Marginal fuel-mix percentages of unconstrained pricing intervals, 2010.

3.4.11 Real-Time Reserves and Reserve Payments

In real time, the dispatch of resources to meet the energy and reserve requirements is jointly optimized. In the presence of a binding reserve constraint, the dispatch will, if possible, reduce the output of an otherwise economic unit in the energy market to create reserves on the system. When this happens, the real-time reserve price is equal to the opportunity cost of the resource not dispatched for energy to satisfy the reserve requirement, capped by the Reserve Constraint Penalty Factor (RCPF) (see Section 2.3.2). The reduction in real-time surplus made possible by the completion of several transmission projects in the second quarter of 2009 led to an increase in both the percentage of intervals in which reserves had a positive price and in the prices that resulted. As expected, this reduction in the availability of reserves from on-line resources continued into 2010, as shown in Table 3-8, which shows the average price during the intervals in which the constraints were binding.

Table 3-8
Average TMSR Price for Intervals with Nonzero Prices by Quarter, 2009 to 2010

	Q1	Q2	Q3	Q4
2009 average TMSR price for intervals with nonzero prices[a]	$23.74	$15.65	$21.11	$42.76
2010 average TMSR price for intervals with nonzero prices[a]	$57.06	$38.08	$47.57	$14.89

(a) TMSR refers to 10-minute spinning reserve (see to Section 2.3).

The supply of 10- and 30-minute reserve capability was further reduced in the second half of 2010 by the outage of one of the region's large flexible generators. Lower reserve prices in the fourth quarter were the result of the return of the generator and additional on-line capacity created by a requirement to carry as 10-minute reserve through the end of the year 112% (rather than 100%) of the system's largest first-contingency loss. The requirement was imposed by the North American Electric Reliability Corporation (NERC) in response to the September 2 event.

Table 3-9 shows, for each reserve product and zone combination, the average real-time five-minute-interval reserve clearing prices during intervals with nonzero prices and the percentage of nonzero-priced intervals. The percentage of nonzero-priced intervals is an indicator of the frequency of binding reserve constraints. The NEMA/Boston and Rest-of-System reserve constraints bound less frequently, but at higher prices, than the Connecticut and Southwest Connecticut reserve constraints.

Table 3-9
Real-Time Reserve Clearing Prices for Nonzero Price Intervals, 2010

Reserve Zone	TMSR[(a)]		TMNSR[(a)]		TMOR[(a)]	
	Price ($/MWh)	% Nonzero Intervals	Price ($/MWh)	% Nonzero Intervals	Price ($/MWh)	% Nonzero Intervals
CT	$33.45	5.31%	$77.86	1.51%	$67.31	0.65%
SWCT	$33.45	5.31%	$77.86	1.51%	$67.31	0.65%
NEMA/Boston	$33.91	5.28%	$80.34	1.48%	$72.13	0.62%
Rest of System	$33.55	5.28%	$79.05	1.48%	$69.71	0.62%

(a) TMSR refers to 10-minute spinning reserve. TMNSR refers to 10-minute nonspinning reserve. TMOR refers to 30-minute operating reserves. See to Section 2.3.

Total real-time reserve payments in 2010 were $18.7 million, an increase from $7.9 million in 2009. Table 3-10 shows real-time reserve payments by product. From 2009 to 2010, real-time payments for 10-minute spinning reserve increased by 133%, and 10-minute nonspinning reserve costs increased by 126%. Payments for all 30-minute operating-reserve products increased by 266%. The large increase in 2010 payments was due in part to the extended, unexpected outage of a large resource and higher load levels during the summer.

Table 3-10
Real-Time Reserve Payments, 2008 to 2010 ($/MWh)

Year	Systemwide TMSR	Systemwide TMNSR	Systemwide TMOR	SWCT TMOR	CT TMOR	NEMA/ Boston TMOR	Total
2008	9,802,141	6,430,973	88,481	324,020	77,914	75,553	16,799,082
2009	4,294,434	3,051,208	105,467	172,563	89,318	138,834	7,851,823
2010	9,996,133	6,896,247	639,041	762,404	342,996	105,824	18,742,645

3.4.12 Net Interchange with Neighboring Regions

During 2010, New England was a net importer of power, with net imports from Canada exceeding net exports to New York. Net interchange with neighboring balancing authority areas totaled 5,439 GWh for 2010, or about 4.2% of total load. Figure 3-25 shows imports and exports by interface. Average metered flow by hour for all external interfaces is included in the appendix, Section 8.1.

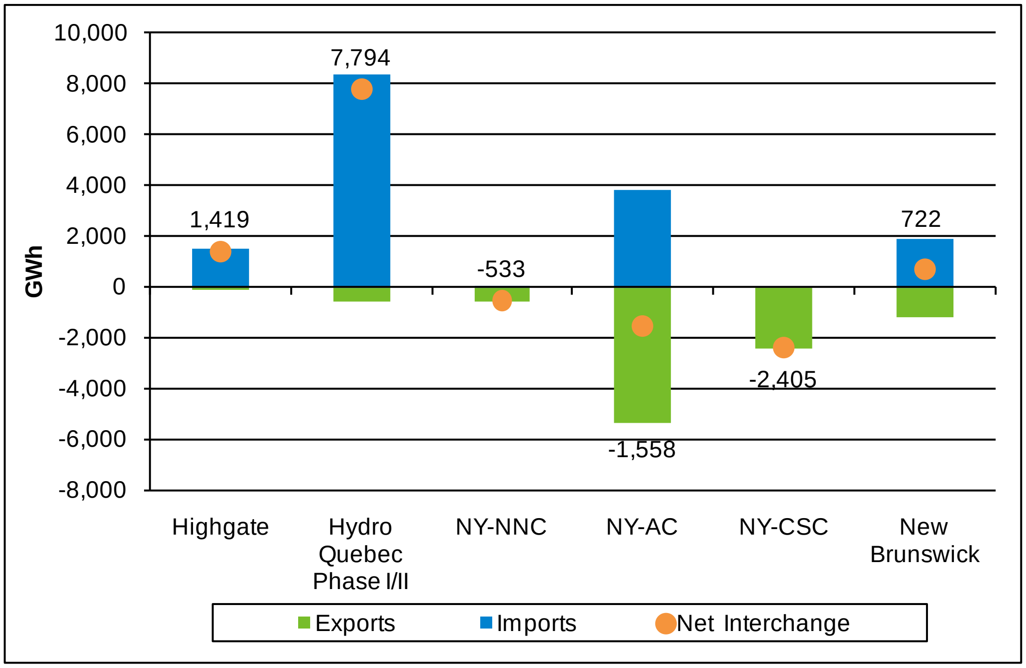

Figure 3-25: Imports and exports by interface, 2010.

Note: NNC stands for the Norwalk Harbor–Northport, NY, cable-replacement project (formerly known as the 1385 cable). NY–AC stands for the New York Alternating-Current Interface. CSC stands for the Cross-Sound Cable.

3.4.13 Minimum Generation Emergencies

The declaration of a Minimum Generation Emergency resets the economic minimums of resources down to their emergency minimums (if available) to gain additional dispatchable range and administratively sets LMPs to zero. Minimum Generation Emergencies are called when the on-line generation comes close to exceeding system load plus net imports and the generation is all operating at its economic minimum.

The number of hours with Minimum Generation Emergency conditions decreased in 2010, from a total of 82 hours over nine months during 2009 to 34.5 hours over five months in 2010, primarily because of higher loads. Additional information on Minimum Generation Emergencies is included in Section 8.4.

3.4.14 Generating Unit Availability

Table 3-11 reports the annual Weighted Equivalent Availability Factors (WEAFs) of New England generating units for 2001 to 2010.[111] Generator availability has remained consistently high since the implementation of markets in New England. As shown, the availability of generators increased to a high of 90% in 2007, dropping to 86% in 2008, and then increasing to 88% in 2010.

[111] The term *weighted* means that averaging is proportional to unit size, so that a 100 MW unit counts 10 times more than a 10 MW unit. *Equivalent* means that both deratings (partial outages) and full-unit outages are counted proportionally to the available megawatts.

Table 3-11
New England System Weighted Equivalent Availability Factors (%)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
System average	89	88	88	88	89	89	90	86	87	88
Fossil steam	84	85	87	86	86	88	87	85	89	88
Coal	88	84	84	83	88	84	87	81	82	83
Coal/oil	86	74	84	88	88	85	79	90	84	86
Oil	84	86	84	84	84	89	84	80	91	90
Oil/gas	80	84	91	87	84	91	89	89	92	90
Wood/refuse	95	94	94	93	93	93	92	92	89	91
Nuclear	91	91	91	94	89	93	92	90	89	94
Jet engine	92	94	94	97	95	96	97	95	97	95
Combustion turbine	89	93	93	97	95	95	94	90	94	95
Combined cycle	84	90	85	86	86	84	86	83	81	86
Pre-1999 combined cycle	94	92	91	92	92	92	92	92	88	91
New installed (1999–2008) combined cycle	76	90	84	84	86	81	83	80	79	85
Hydro	95	96	95	94	94	96	96	97	96	94
Pumped storage	93	87	92	90	92	91	98	93	96	56
Diesel	98	98	98	95	98	99	97	98	96	95

3.5 Congestion Revenue and Financial Transmission Rights

This section provides information on the value of congestion revenue and the results of the Financial Transmission Rights markets.

3.5.1 Congestion and Congestion Revenue

Figure 3-26 shows total congestion revenue by month from 2008 through 2010. Congestion revenues dropped dramatically in 2009 after the completion of transmission projects in Connecticut and Boston. Total congestion revenue increased 51% from 2009 to 2010, from $25 million to $38 million. This increase was caused by higher seasonal load levels that led to the more frequent binding of constraints; higher input fuel prices; and the extended, unexpected outage of a large resource.

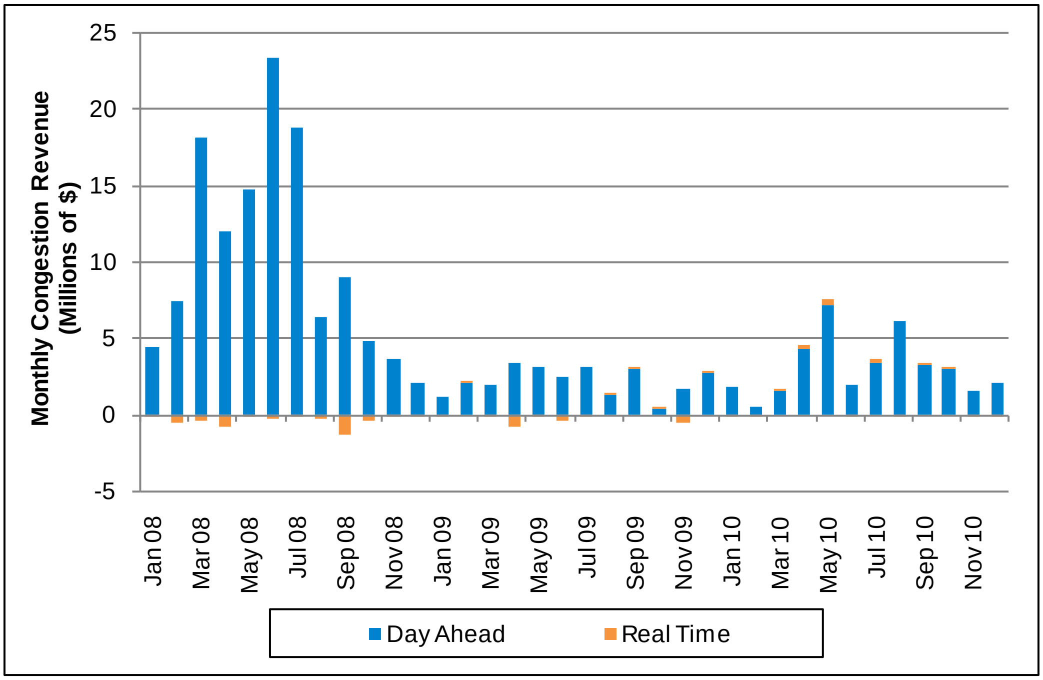

Figure 3-26: Day-ahead and real-time congestion revenue by month, 2008 to 2010 (millions of $).

3.5.2 Financial Transmission Rights and Auction Revenue Rights

The ISO conducts annual and monthly auctions for FTRs. Revenues collected from the auctions are distributed back to market participants according to the ISO tariff and *Market Rule 1*.

3.5.2.1 FTR Auction Results

The annual auction for FTRs for the 2010 calendar year was held in December 2009 and offered 50% of the system's transmission capability. FTR auctions also were held for each month in 2010. In each of the monthly auctions, the remaining balance of the transmission capability, accounting for expected outages within that month, is made available.[112] The number of participants bidding in each auction ranged from 29 participants in the November monthly auction to 40 participants in the April 2010 auction, similar to the range of FTR participation in previous years. In 2010, revenue from the 12 monthly auctions and the single annual auction totaled $30.2 million, a 58% drop from 2009.

Figure 3-27 shows the annual and average monthly megawatt volume that cleared the FTR auctions for 2008 through 2010. The volume of annual megawatts dropped from 2008, while the average volume in the monthly auctions increased slightly compared with previous years. Figure 3-28 shows the average annual FTR price converted into a monthly value (simply by dividing the annual value by 12) and the average monthly auction prices for 2008 through 2010. The average annual price in 2010 dropped significantly from the prior year as participants realized that the transmission projects completed in 2008 and 2009 significantly decreased congestion. While the monthly average quantity of megawatts transacted increased from 2009, the average price dropped from $42/MW to $35/MW.

[112] During each of the monthly FTR auctions, the remaining capacity of the transmission system is sold, except for 5% to account for unplanned outages.

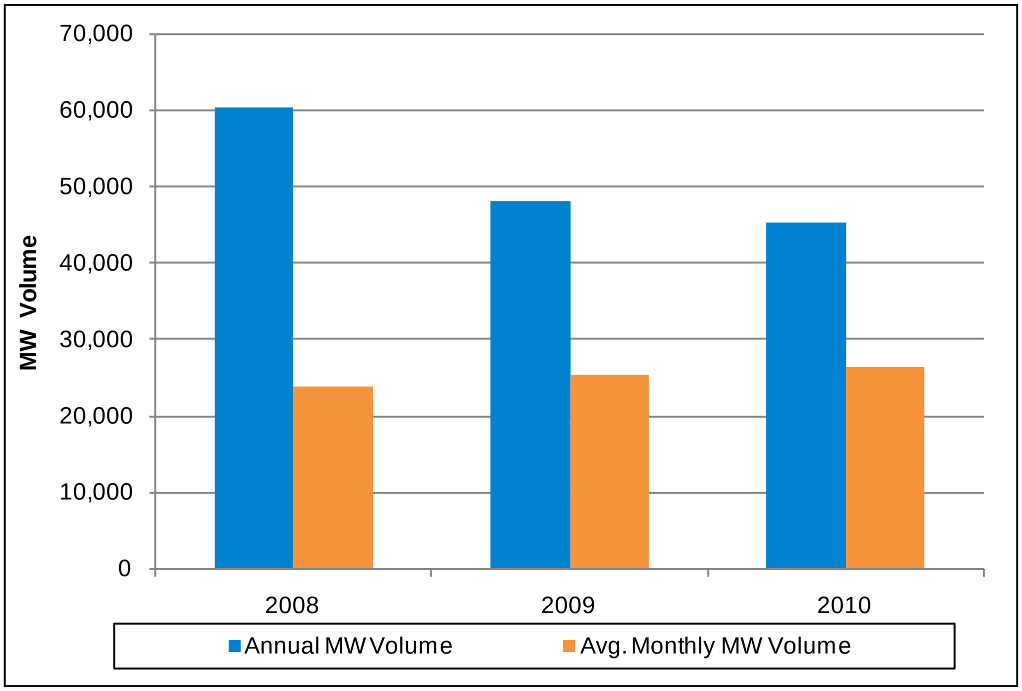

Figure 3-27: Annual and average monthly auction volumes, 2008 to 2010.

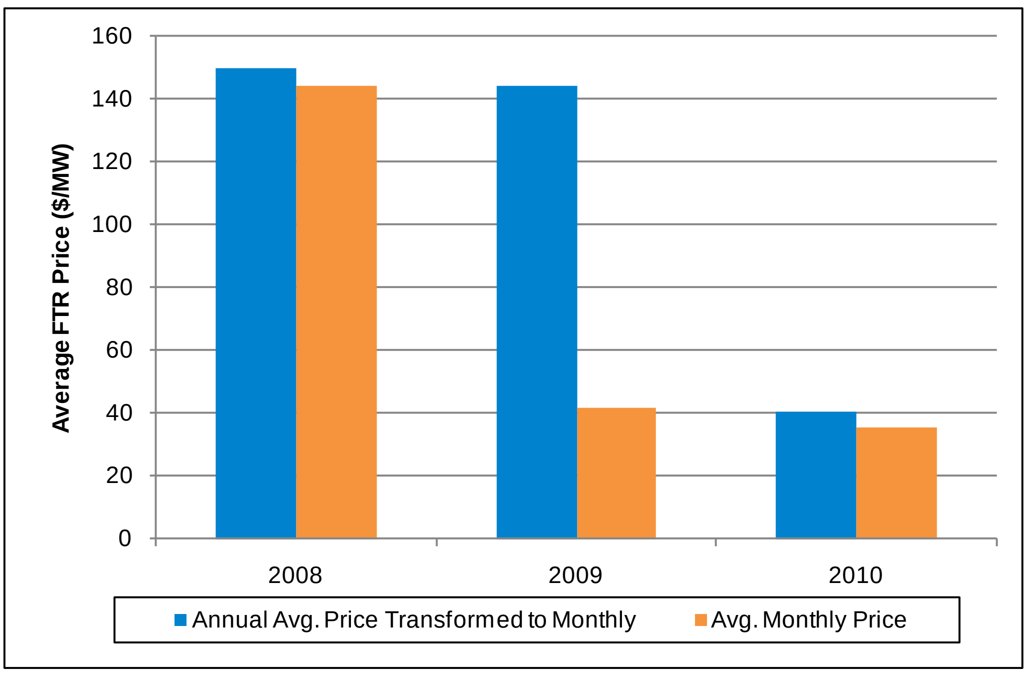

Figure 3-28: Annual prices converted to monthly equivalent price and average monthly auction prices, 2008 to 2010.

Table 3-12 shows the auction revenue as a percentage of day-ahead congestion revenue for 2008 through 2010. For 2008, the FTR prices, and the associated auction revenues, estimated future day-ahead congestion reasonably well, while in 2009, the annual auction revenues from the sale of FTRs exceeded realized day-ahead congestion by 166%. This indicated that market participants did not accurately predict the drop in congestion revenues that occurred in 2009. This mismatch was generally corrected, first in the monthly auctions for 2009 and then in the annual 2010 FTR auction. Total auction revenues dropped from $71.1 million in 2009 to $30.2 million, and congestion increased, which resulted in auction revenues being lower than day-ahead congestion revenues by 19%.

Table 3-12
Comparison of Day-Ahead Congestion Revenue to Auction Revenue, 2008 through 2010

	Day-Ahead Congestion Revenue (Millions $)	Total Auction Revenue (Millions $)	Auction Revenue as % of Day-Ahead Congestion Revenue
2008	125.4	116.7	93%
2009	26.7	71.1	266%
2010	37.3	30.2	81%

3.5.2.2 FTR Auction Revenue Distribution

The FTR settlements distribute congestion revenue from the Day-Ahead and Real-Time Energy Markets to FTR holders. The revenues from the auction in which FTRs are purchased are distributed to holders of Qualified Upgrade Awards and Auction Revenue Rights holders (see Section 2.6.3). As shown in Table 3-13, the majority of the auction revenue is distributed to Auction Revenue Rights holders.

Table 3-13
Total Auction Revenue Distribution, 2008 through 2010 ($)

	2008	2009	2010
QUAs	7,997,938	2,940,675	3,074,310
Excepted transactions[a]	137,592	532	2,160
NEMA contract holders	207,897	154,826	130,563
ARR holders	108,387,117	67,957,265	26,950,479
Total auction revenue	116,730,543	71,053,298	30,157,511

(a) *Excepted transactions* are certain power transfers and other uses of the pool transmission facilities effected under transmission agreements in effect on November 1, 1996, as specified in the ISO's *Open Access Transmission Tariff*, Section II.40, and for the time periods described therein. These transactions are included in the OATT, Attachments G, G-1 and G-3; http://www.iso-ne.com/regulatory/tariff/index.html.

In 2010, about 89% of the total auction revenue was distributed to load-share ARR holders. Figure 3-29 shows the percentage of the total ARR distributions by load zone. In 2010, most ARRs were distributed to participants in the Connecticut and WCMA load zones. By design, this is consistent with the areas in which congestion occurs on the system.

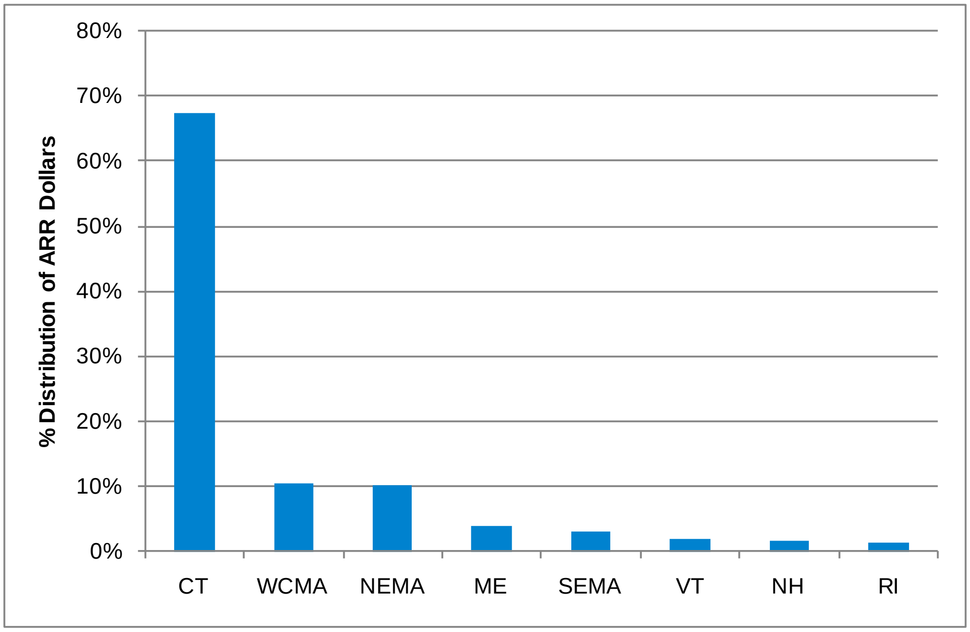

Figure 3-29: Load-share ARR distribution by load zone, 2010.

3.5.2.3 FTR Profitability and Hedging Performance

Figure 3-30 compares two concepts at a participant level: (1) the FTR net revenues and (2) a "net hedge" of FTR and ARR revenues combined. The figure shows that most participants were able to profit from the net hedge. The total net position of participants that both received auction revenues and participated in the FTR market was almost $4.6 million. The remaining auction revenue was distributed to ARR and QUA holders that did not participate in the FTR market.

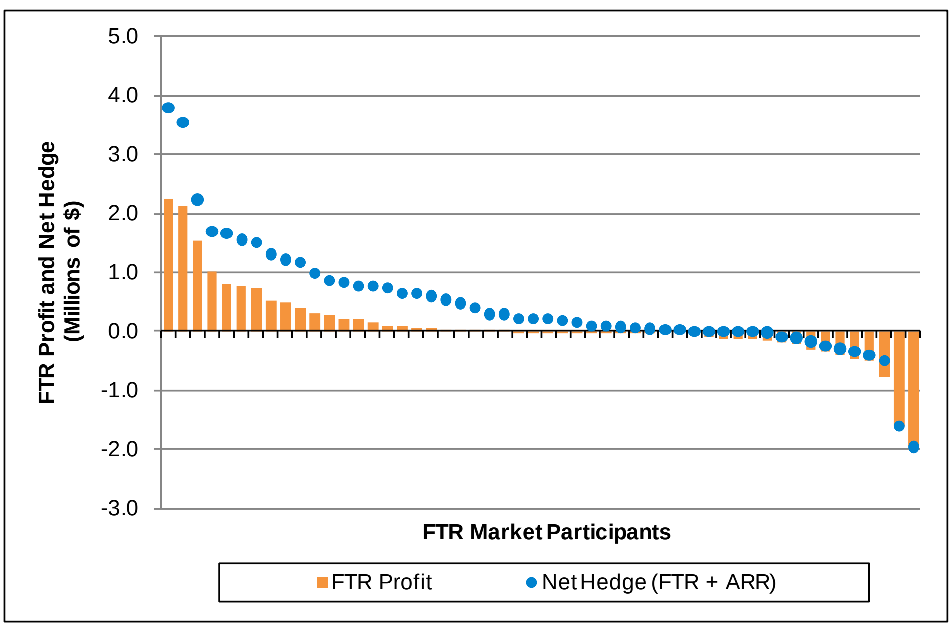

Figure 3-30: Overlay of FTR participant profitability and total hedge after including ARR revenue, 2010.

The Congestion Revenue Balancing Fund is made up of the monthly revenue surpluses and shortfalls accrued during the year (see Section 2.6.2).[113] In 2010, the year-end balance of the Congestion Revenue Balancing Fund was $ 3,183,503, while the sum of monthly shortfalls was −$1,226,872. The FTR holders who were not paid because of the monthly shortfalls were made whole at the end of the year through the Congestion Revenue Balancing Fund. The money remaining in the Congestion Revenue Balancing Fund goes back to load-serving entities that paid congestion charges.

3.6 Demand Resources

As explained in Section 2.7, the transition to the Forward Capacity Market on June 1, 2010, brought several changes to the ISO's demand-response programs. Table 3-14 lists demand-response programs and demand-response resource types eligible to receive capacity payments during 2010. Resources participating in programs termed "active" are required to respond to dispatch instructions from the ISO. Resources termed "passive" do not receive dispatch instructions from the ISO. Instead, these resources curtail their electricity use at set times throughout the year. Other demand-response programs pay resources for reducing load when prices exceed certain threshold levels. These programs are open to both capacity resources and other resources that register solely to participate in these price-responsive demand categories.

Table 3-14
Demand-Response Programs

Program	Active or Passive?	Can Asset Participate in DALRP?	Can ISO Call Asset During OP 4?
FCM Resource Category			
Real-time demand response (RTDR)	Active	Yes	Yes (Action 2)
Real-time emergency generation (RTEG)	Active	No	Yes (Action 6)
On peak	Passive	No	No
Seasonal peak	Passive	No	No
Demand-Response Programs (retired at end of the transition period)			
Real-time profiled response	Active	Yes	Yes (Action 3)[(a)]
Real-time two-hour demand response	Active	Yes	Yes (Action 3)[(a)]
Real-time 30-minute demand response (with or without emergency generation)	Active	Yes	Yes (Actions 9 or 12)[(a)]
Other demand resources (ODRs)	Passive	No	
Demand-Response Programs (continued from the transition period)			
Real-time price response (RTPR)	Active	Yes	No
Day-ahead load response (DALRP)	The DALRP is open to RTPR and RTDR assets. Assets receive energy market payments for DALRP participation; there is no additional capacity payment.		

(a) OP 4 action numbers changed when the procedure was revised as part of FCM implementation.

[113] Table 8-10 in Section 8.1.4 shows the components of the Congestion Revenue Balancing Fund for each month of 2010.

3.6.1 Demand-Resource Program Participation

Table 3-15 shows monthly program enrollments for demand response and ODRs for the pre-and post-FCM periods for 2010. The megawatts of demand resources participating in ISO markets decreased when the new programs went into effect on June 1, 2010.

Table 3-15
Demand-Response Program Enrollments, Pre-FCM and Post-FCM (MW)

Pre-FCM[a]	**Real-Time Price Response Resource**	**30-Min. Real-Time Demand-Response Resource**	**2-Hr. Real-Time Demand Response w/ Gen.**	**Profiled Demand-Response Resource**	**Other Demand Resources**	**Total Demand-Resource Enrollments**
	65	1,999	217	17	554	2,852
Post-FCM[b]	**Real-Time Demand-Response Resource**	**Real-Time Emergency Generation Resource**	**On-Peak Demand Resource**	**Seasonal-Peak Demand Resource**		**Total Demand-Resource Enrollments**
	826	645	499	146		2,116

(a) Pre-FCM numbers are May 2010 enrollments.

(b) Post-FCM numbers are June 2010 enrollments.

The drop in resource capability from the transition period to the FCM is likely the result of improved methods for measuring demand reductions and the performance requirements under the FCM compared with the transition period. For example, during the transition period, reductions were measured as the largest reduction during a five-minute dispatch interval; under the FCM, they are measured over an hour-long period. The performance requirements under the FCM appear to have caused demand-resource providers to aggregate more customers to support a given capacity supply obligation than they aggregated under the transition period.

3.6.2 Demand-Response Interruptions

The system conditions under which the ISO will ask active demand resources to reduce load vary by resource or program type, as described in Section 2.7. The reductions by passive demand resources, which do not reduce load in response to an ISO dispatch instruction, are measured over specified hours based on engineering estimates of the load reduction achieved by the installation of the measure. The reductions in a given month are calculated according to the number of load-reducing installations of the measure and the weather, if appropriate.

Table 3-16 details the payments made to demand-response programs in 2010. Payments for all demand-resource programs totaled $144 million in 2010. Over 93% of this total was capacity market payments. Resources are not paid for interruptions associated with OP 4 actions. However, an asset that clears in the DALRP in the same hour it responds to an OP 4 action is paid the real-time LMP for interruptions above its DALRP megawatts, just like on any other day. In Table 3-16, these payments are all included in the DALRP total.

Table 3-16
Demand-Response Payments, 2010 ($)

Period	DALRP Payments	RTPR Payments	Capacity Payments	Total
Jan to May	$515,497	$278,571	$74,251,383	$75,045,451
Jun to Dec	$7,865,707	$625,518	$60,205,037	$68,696,262
Total 2010	$8,381,204	$904,089	$134,456,420	$143,741,713

Payments to resources in the DALRP and RTPR program were higher in 2010 than in 2009. Participants in the DALRP were paid almost $8.4 million in 2010, compared with $2.5 million in 2009 and $6.7 million in 2008. Payments in the real-time program were $904,089, compared with $597,455 in 2009 and $5.1 million in 2008.

3.6.3 June 24 Demand Resource Performance

June 24, 2010, provided the first opportunity for demand resources with a capacity supply obligation to perform in a market context in response to real-time dispatch instructions. Table 3-17 shows average demand-response performance during the OP 4 event on June 24. From 1:48 p.m. until 4:24 p.m., the ISO dispatched 669 MW of demand response to curtail the rising system load. By 4:24 p.m., loads had decreased enough to permit the reduction of dispatched demand response from 669 MW to 300 MW. The control room operators stopped dispatching demand response at 4:57 pm.

Table 3-17
Demand-Response Performance, June 24 2010

Load Zone	Total Net CSO	Average Aggregate Performance[(a)]	Percentage
Connecticut	226	170	75%
WCMA	80	79	99%
NEMA	71	46	65%
SEMA	45	30	66%
Rhode Island	28	27	97%
Vermont	24	29	122%
New Hampshire	29	33	113%
Maine	166	239	144%
New England	**669**	**653**	**98%**

(a) Performance levels measured between 1:50 p.m. and 4:24 p.m.

The demand resources appeared to have performed well in aggregate, but individually and on the zonal level, performance was mixed. At the zonal level, only Rhode Island and Western Massachusetts performed within 10% of the net CSO.[114] All other zones performed by reducing load

[114] "Within 10%" of the CSO was chosen as the performance benchmark because it is consistent with the standard to which generation is held when assessing whether it has followed dispatch instructions.

either too much or too little. Demand resources in Maine overperformed by reducing load to 144% of net CSO, a reduction of 72.78 MW above the desired level. On the other hand, Connecticut underperformed by reducing load to 75% of net CSO, a deficiency in demand reduction of almost 57 MW.

As the performance data are disaggregated from the zonal level to the resource level, performance becomes even more skewed. For the June 24 event, Figure 3-31 shows a histogram (with 10% interval bins) of demand-resource performance by resource as a percentage of CSO megawatts. Resources that performed within the 90 to 110% generator-dispatch threshold of CSO totaled 142 MW, or 22% of the total demand-resource CSO of 653 MW.

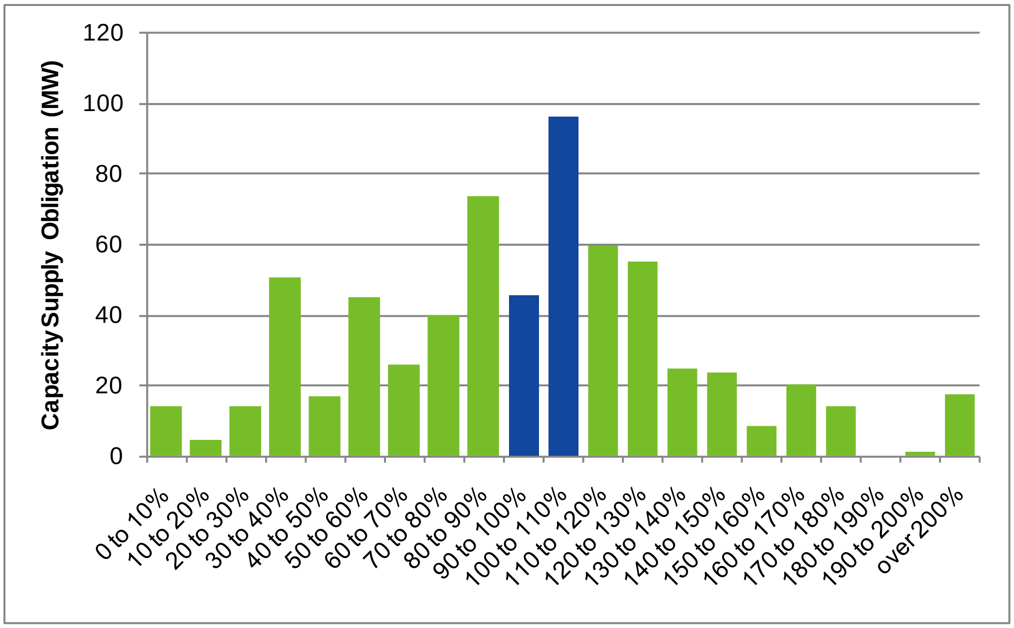

Figure 3-31: Histogram of demand-resource dispatch performance at 100% dispatch compared with capacity supply obligation; demand-resource reduction as a percentage of CSO during the June 24, 2010, OP 4 event.

Notes: The blue bars denote the resources that performed in the 90 to 110% range for generation dispatch of CSO.

The performance discrepancies identified appear to be the result of several factors, including possible incentive problems in the DALRP, a desire or need by some demand-response providers to use the event to audit new assets, and the FCM provisions that allow overperforming demand-response resources to receive an allocation of the penalties paid by underperforming resources. The IMM has not yet completed its analysis of all these factors. The IMM will continue to monitor the performance of demand resources and may recommend design changes based on further observations and analysis.

3.6.4 Analysis of Price-Response Programs

The two price-response programs (the Real-Time Price-Response Program and the Day-Ahead Load-Response Program) were originally scheduled to expire on June 1, 2010. However, both programs have been extended for two additional years, to June 1, 2012, while the ISO and its stakeholders determine how to integrate price-responsive demand into the energy markets.[115] The filing extension included provisions to make a needed change to the DALRP eligibility criteria in addition to revising the programs' expiration dates. No changes were made to the payment rates, minimum offer prices, activation criteria, cost-allocation method, or participants' rights and obligations.

3.6.4.1 Real-Time Price-Response Program Interruptions

The Real-Time Price-Response Program is activated on weekdays when any zonal price during hour ending (HE) 8:00 a.m. to HE 6:00 p.m. is forecast to be $100/MWh or higher.[116] Forecasts include the Day-Ahead Energy Market prices and LMPs calculated during the ongoing RAA process. When the program is activated, real-time price-response resources may reduce load during HE 2:00 p.m. to HE 5:00 p.m. in the winter and HE 12:00 p.m. (noon) to HE 5:00 p.m. in the summer. Table 3-18 shows the number of days and megawatt-hours of interruption for the RTPR program in 2010.

Table 3-18
Real-Time Price-Response Interruptions in 2010

Month	# of Days with RTPR Event	MWh Interrupted in Real Time	Payment for RTPR ($)
Jan	15	1,025	$105,026
Feb	8	464	$50,475
Mar	3	197	$19,680
Apr	3	274	$27,423
May	8	712	$75,968
Jun	8	791	$92,625
Jul	17	1,930	$231,957
Aug	13	1,390	$169,513
Sep	7	799	$89,328
Oct	1	30	$3,042
Nov	8	66	$6,634
Dec	12	220	$23,460
Total	103	7,898	$895,131

Table 3-19 shows Hub LMPs on days when the RTPR program was activated. It compares average real-time LMPs for the hours of the program activation with the average of the highest daily day-ahead and RAA LMPs during HE 8:00 a.m. to HE 6:00 p.m. (the trigger hours) on days when the program was activated.

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[115] For more information, see *ISO New England Inc. and New England Power Pool, Tariff Revisions Regarding Extension of the Real-Time Price Response Program and Day-Ahead Load Response Program; Docket No. ER09-___-000*, FERC filing, Docket No. ER09-1737-000 (September 23, 2009), http://www.iso-ne.com/regulatory/ferc/filings/2009/sep/er09-___-000_9-23-09_price_load_response_ext.pdf.

[116] *Hour ending* denotes the preceding hourly time period. For example, 12:01 a.m. to 1:00 a.m. is hour ending 1:00 a.m. Hour ending 6:00 p.m. is the time period from 5:01 p.m. to 6:00 p.m.

Table 3-19
Average Hub LMPs for Real-Time Price-Response Program Hours, 2010 ($/MWh)

Month	Real-Time LMPs, Activated Hours	Day-Ahead LMPs, Trigger Hours	RAA LMPs, Trigger Hours
Jan	$59.33	$90.46	$10,370.88
Feb	$64.57	$78.51	$508.18
Mar	$53.47	$48.65	$487.60
Apr	$40.47	$46.50	$56,849.92
May	$78.86	$57.64	$36,404.54
Jun	$95.05	$79.07	$502.81
Jul	$102.32	$123.57	$4,659.52
Aug	$107.73	$111.99	$6,177.17
Sep	$81.61	$80.90	$304.59
Oct	$38.03	$50.78	$213.47
Nov	$47.06	$65.63	$754.76
Dec	$78.52	$112.28	$5,341.34

High LMPs calculated in the RAA process triggered most of the activation of the Real-Time Price-Response Program in 2010.[117] Prices in the Day-Ahead Energy Market and Real-Time Energy Market were much lower than the LMPs from the RAA process. The Hub day-ahead LMP was $100/MWh or more on only 35 of the 104 days when the program was activated. If the price-response program is extended, the IMM recommends discontinuing the use of the prices from the RAA as a trigger for the Real-Time Price-Response Program.

3.6.4.2 Analysis of the Day-Ahead Load-Response Program

Before the introduction of the FCM, assets enrolled in the price-response program or any of the reliability programs were eligible to participate in the DALRP. At the end of May 2010, 2,852 MW were eligible to participate in the DALRP, of which 530 MW were enrolled. When the FCM demand-response programs went into effect on June 1, 2010, the 1,202 MW enrolled in the price-response and RTDR programs became eligible to participate, and 685 MW were enrolled.[118] Enrollments increased to 773 MW by December 2010.

While megawatt-quantity enrollment increases were modest during the course of the year, the number of assets participating rose by more than six-fold. Table 3-20 shows the number of assets enrolled in the DALRP and their total capacity.

[117] The RAA process is used to schedule capacity (see Section 2.1.2.2). It was not intended as a price forecasting tool. Many RAA assumptions would have to be changed to make this process suitable for price forecasting.

[118] According to *Market Rule 1*, Appendix E (http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf), a market participant may submit an offer in the Day-Ahead Load-Response Program for a load-response program asset in increments of 100 kW or more and concurrent with the Day-Ahead Energy Market. Load-response program assets may be aggregated to reach the 100 kW minimum.

Table 3-20
Number of Assets and Maximum Capacity of Enrolled Assets in the Day-Ahead Load-Response Program, 2010 (MW)

Month	Number of Assets	Maximum Capacity of Enrolled Assets (MW)[(a)]
Jan	144	548
Feb	154	564
Mar	136	536
Apr	135	533
May	133	530
Jun	826	685
Jul	879	703
Aug	878	701
Sep	878	701
Oct	878	701
Nov	878	710
Dec	922	773

(a) The table shows the maximum interruptible capacity for each asset for January to May and estimated reduction in megawatts for June to December. This number typically is greater than the megawatts that participants enrolled in the DALRP because their interruptions are not limited to the DALRP enrollment. Thus the maximum capacity and estimated reduction numbers are more useful representations of DALRP megawatts.

DALRP Offers. Although not required to place offers to interrupt, assets enrolled in the DALRP may place such offers by noon on the day before the operating day. Placed offers must be at or above the monthly DALRP minimum offer price and must offer at least 100 kW.[119] DALRP offers are valid for hours ending 7:00 a.m. to 6:00 p.m., with a single price and megawatt quantity for the entire offer period. A DALRP offer may clear for some or all of the hours for which it was submitted.

Figure 3-32 compares the monthly DALRP minimum offer prices with the average day-ahead LMP at the Hub for nonholiday weekdays between 7:00 a.m. and 6:00 p.m. The minimum offer price was lower than the average LMP in May through September. When market prices consistently exceed the minimum offer price, resources can clear in the DALRP program each day. But the baseline for a resource that clears in the program on a particular day is not reset using the resource’s consumption during that day. This provides an opportunity for resources to create an inflated baseline by artificially increasing their loads while their baseline is being calculated and then freezing that baseline by offering into the program everyday.

[119] As specified in the tariff, the minimum offer price is calculated as a heat rate of 11.37 MMBtu/MWh multiplied by a monthly fuel index.

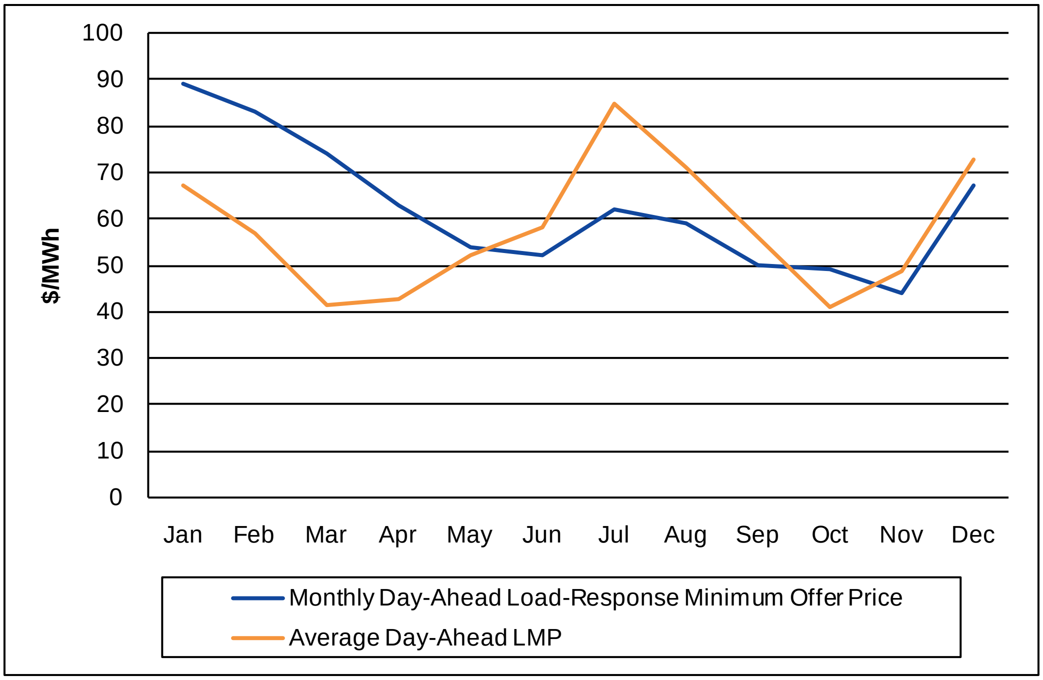

Figure 3-32: DALRP minimum offer price compared with monthly average day-ahead LMPs at the Hub, 2010.

Table 3-21 shows DALRP average monthly offered quantities and prices along with the minimum offer price. In every month except December, the average offer price was the same as the minimum offer price. In December, the average offer exceeded the minimum offer price by $27.95/MWh. This was a result of 96 assets offering at $1,000/MWh in the last eight days of the month. The IMM investigated this behavior and found that this was done because it was administratively easier than removing the assets from the market.

Table 3-21
DALRP Offers Compared with Minimum Offer Prices, 2010 (MW and $/MWh)

Month	Average MW per Offer	Average Offer Price ($/MWh)	Minimum Offer Price Threshold ($/MWh)
Jan	0.105	$89.00	$89.00
Feb	0.101	$83.00	$83.00
Mar	0.100	$74.00	$74.00
Apr	0.100	$63.00	$63.00
May	0.100	$54.00	$54.00
Jun	0.100	$52.00	$52.00
Jul	0.100	$62.00	$62.00
Aug	0.100	$59.00	$59.00
Sep	0.101	$50.00	$50.00
Oct	0.100	$49.00	$49.00
Nov	0.100	$44.00	$44.00
Dec	0.101	$94.95	$67.00

Virtually all assets that offer into the DALRP offer the minimum quantity (100 kW) at the minimum offer price. Actual real-time interruptions are determined by comparing an asset's actual load with the asset's adjusted baseline.[120] Any difference between the quantity that cleared day-ahead and the actual interruption is settled as a real-time deviation.

Cleared Offers and Payments. Offers that clear are paid the day-ahead zonal LMP, and any deviations from the day-ahead cleared quantity are settled at the real-time zonal LMP. For example, an asset that cleared 0.1 MW in the DALRP and had an adjusted baseline of 5 MW and a real-time load of 4 MW would have a real-time deviation of 0.9 MW. The asset would be paid the day-ahead zonal LMP times 0.1 MW and the real-time zonal LMP times 0.9 MW. However, if the asset had a real-time load of 6 MW, it still would be paid the day-ahead zonal LMP times 0.1 MW, but it would be *charged* the real-time zonal LMP times 1.1 MW.

Table 3-22 shows the number of days in each month when DALRP assets had cleared offers, along with megawatt quantities and payments. Table 3-23 shows daily offer volumes.

[120] The method for establishing demand-asset baselines is defined in *Measurement and Verification of Demand-Reduction Value from Demand Resources*, Manual M-MVDR (May 6, 2011), http://www.iso-ne.com/rules_proceds/isone_mnls/index.html.

Table 3-22
DALRP Cleared Offers and Payments (MW and $)

Month	# of Days with DALRP MW Cleared	Day-Ahead Cleared MW	MW Interrupted in Real Time	Real-Time MW Deviation from Day-Ahead Cleared	Payment for Day-Ahead Cleared MW	Payment for Real-Time Deviation MW	Total Payment
Jan	8	361	2,226	1,865	$36,505	$176,460	$212,966
Feb	3	30	129	99	$2,663	$8,971	$11,634
Mar	0	0	0	0	0	0	0
Apr	1	9	16	7	$598	$324	$922
May	20	829	4,096	3,268	$50,647	$241,328	$291,976
Jun	22	11,343	11,464	121	$754,801	$46,265	$801,067
Jul	19	13,965	16,635	2,670	$1,398,747	$279,577	$1,678,325
Aug	18	11,474	14,574	3,100	$1,038,619	$247,909	$1,286,528
Sep	21	12,109	9,487	−2,621	$768,048	−$141,409	$626,639
Oct	7	348	402	54	$17,542	$3,104	$20,645
Nov	20	15,292	21,363	6,071	$781,052	$259,007	$1,040,059
Dec	19	9,992	20,189	10,197	$950,342	$842,119	$1,792,461
Total	158	75,752	100,582	24,831	$5,799,564	$1,963,656	$7,763,220

Table 3-23
Average Hourly DALRP Offers (MW and $/MWh)

Month	Hourly Offers (MW)	Enrolled Capacity (MW)	Minimum Offer Price ($/MWh)	Average Offer Price ($/MWh)
Jan	14.416	548.1	89.00	89.00
Feb	13.889	564.4	83.00	83.00
Mar	12.194	536.1	74.00	74.00
Apr	12.077	533.1	63.00	63.00
May	11.977	530.1	54.00	54.00
Jun	81.057	685.1	52.00	52.00
Jul	87.155	703.4	62.00	62.00
Aug	87.094	701.5	59.00	59.00
Sep	87.600	701.5	50.00	50.00
Oct	86.655	701.5	49.00	49.00
Nov	86.524	710.0	44.00	44.00
Dec	90.384	773.2	67.00	95.00

Load Reductions. A review of Table 3-22 and Table 3-23 raises concerns about whether payments to resources in the DALRP are, in fact, for apparent load reductions that result from differences between actual loads and baselines rather than for genuine load reductions. Table 3-22 shows that in every month except one since May 2010, resources cleared at least 18 of the weekdays in the month. Because virtually all resources offer in at the minimum offer price and at 100 kW, all participants in the program are committing to reduce load most weekdays in the month, which is unlikely. It is more probable that the DALRP program design puts little risk on program participants, thereby encouraging them to take advantage of any hours in which their actual load is less than the baseline.

The 100 kW minimum offer level allows assets to participate in the DALRP with minimal risk of loss because it enables a participant that does not take any load-reducing action to benefit if its actual load is less than its baseline. Using this bidding strategy and the current market rules, a participant will be paid the entire difference between its real-time consumption and its baseline. This enables participants to benefit from baseline measurement errors that result in apparent reductions while taking on only the risk of purchasing 100 kW in the real-time market rather than the day-ahead market.

To ensure that payments in the DALRP are made, consistent with the rules, only to participants that have taken action to reduce loads, these baselines should minimize the likelihood of paying for apparent, rather than real, reductions. The IMM recommends that participants be paid only for the reductions in their asset's consumption that were offered into the day-ahead market as part of the DALRP. For example, if a load wishes to commit to reduce its load by 1 MW below its baseline, it must offer the full 1 MW into the DALRP. The participant must then ensure that its consumption is 1 MW below its baseline in real time; otherwise, it will be exposed to purchasing back the full 1 MW at the real-time price. To the extent possible, the ISO should set the baseline at the actual consumption level as close to the time of reduction as possible.

Baseline Calculation. The current demand-response baseline calculations have several characteristics that may result in payments in the DALRP and the price-response program to load assets that take no action to reduce load. First, baselines do not include data from days when an asset clears in the DALRP or participates in a RTPR program or reliability event. When an asset clears in the DALRP on sequential days, its baseline is carried forward from the period before it cleared. If this baseline is higher than the asset's current consumption, it can receive payments in the DALRP without taking action to reduce load. To prevent the "freezing" of baselines, the IMM recommends adopting an improved process for establishing initial baselines and developing a more robust and accurate baseline methodology.

This analysis has highlighted the concerns with the current baseline calculation methodology.[121] An asset's baseline is calculated as the average interval load, rounded to the nearest kilowatt, for each interval for each hour of the day. It is intended to represent the asset's typical load without demand-response interruptions.[122] Baselines are calculated using loads from days without interruptions; for days with an interruption, an adjustment is applied to the baseline that is intended to represent the asset's load on the specific day. The adjustment uses the load from a two-hour period before the interruption starts to determine the difference to apply to the baseline.

[121] Manual M-MVDR, Section 6.4.1.1, http://www.iso-ne.com/rules_proceds/isone_mnls/index.html.

[122] The average load interval is five minutes for real-time demand-response and RTEG assets and hourly for the Real-Time Price-Response Program.

Adjustments were included in the program design because prereduction loads on days with interruptions may be different from loads on a typical day. For example, reliability events are more likely to occur on hot summer days, and resources may have higher loads as a result of air cooling on those days. However, on a day when an asset has cleared in the DALRP, a company might decide to cancel a shift for the entire day, resulting in lower-than-normal loads. For this reason, assets that have cleared in the DALRP receive asymmetric adjustments—the baseline will be adjusted upward only. For interruptions during reliability events, the adjusted baseline may be higher or lower than the unadjusted baseline.

When consecutive event days occur, the customer baseline adjustment used on the prior event day is compared with the customer baseline adjustment calculated for the current event day, and the more beneficial adjustment is applied to the customer baseline for the current event day.[123] An asset that shuts down may still receive credit for interrupting its load on an event day, but its interruption will be calculated using its unadjusted baseline—that is, no baseline adjustment will be applied.[124]

The IMM is concerned that, in some cases, baselines and adjusted baselines may not be accurate representations of assets' loads, absent interruptions, and are susceptible to manipulation. The IMM has observed in some cases that assets receive credit for interruptions even though their load in event hours is consistently equal to or higher than their load in nonevent hours. The IMM also has observed that some assets offer into the DALRP every day and are credited with interruptions relative to adjusted baselines every day. This also suggests that the baselines may be misleading and highlights the problem of how to calculate accurate baselines while excluding data from days with extremely frequent interruptions.

In addition to problems with baseline accuracy, the IMM also has noted that some resources designated as "incremental distributed generation" do not have baselines. These resources report their generation to the ISO, and in intervals when they are participating in the DALRP, they report the increment of generation that should be credited as an "interruption." Determining whether their reported incremental generation is the actual amount of load relief provided to the system is difficult.

Further IMM Recommendations. Although the DALRP was extended to June 2012 with no changes to the rules, improvements could be made to the structure to address some problems. The IMM recommends that the rules further clarify that resources should not be permitted to participate in the DALRP during periods when a resource is shut down for reasons unrelated to its participation in the DALRP. The IMM also recommends reevaluating several rules, including the rule associated with the use of asymmetric baselines for assets that clear the DALRP, and particularly the rule that allows the adjustment most favorable to the customer to be carried forward day to day when consecutive event days occur. In addition, the IMM suggests that the ISO implement more rigorous auditing and documentation requirements for demand resources. Access to more detailed information about demand-reduction measures would allow the ISO to verify that the load relief and capacity the market pays for actually is provided.

The IMM is skeptical of the long-term viability of measuring the performance of demand-response programs using baselines to estimate how much energy a participant would have consumed.

[123] Manual M-MVDR, Section 6.4.1.1, http://www.iso-ne.com/rules_proceds/isone_mnls/index.html.

[124] If the asset's actual usage for the two hours preceding the start of the event is equal to or less than 10% of the unadjusted baseline for that day, the asset is considered to be on *shutdown* for that day and no adjustment is applied. Manual M-MVDR, Section 6.4.1.1(4)(iv).

However, FERC Order 745 that addresses demand response will require the ISO to develop baselines to implement FERC's rulemaking for price-responsive demand. Using an estimated baseline may be necessary, however, for reductions committed the day before or several hours before real time. These estimated baselines should reflect the recommendations detailed above.

3.6.5 Data Validation Issues with Demand-Resource Assets

To ensure that demand resources were properly registered and were reporting data accurately, ISO Market Support Services performed data validation checks on demand-response assets, using established maximum load and maximum generation levels starting in June 2010, coincident with the first FCM commitment period and the registration of a large number of new demand resources.[125] Participants were notified when one or more of their assets failed data validation checks during a month. If a participant did not provide revised data that met the data-validation thresholds for an asset, the asset was placed on the exclusion list and its interruptions were set to 0 MW for all intervals in the month. Those intervals were also excluded from the demand-reduction value calculation.[126]

Figure 3-33 shows the number of assets on the exclusion list, the number of assets on the notification list that revised their data and were not placed on the exclusion list, and the percentage of all demand-response assets on the notification and exclusion lists. These data show that, while progress is being made in this area, integrating demand resources into the market is challenging and will require significant effort.

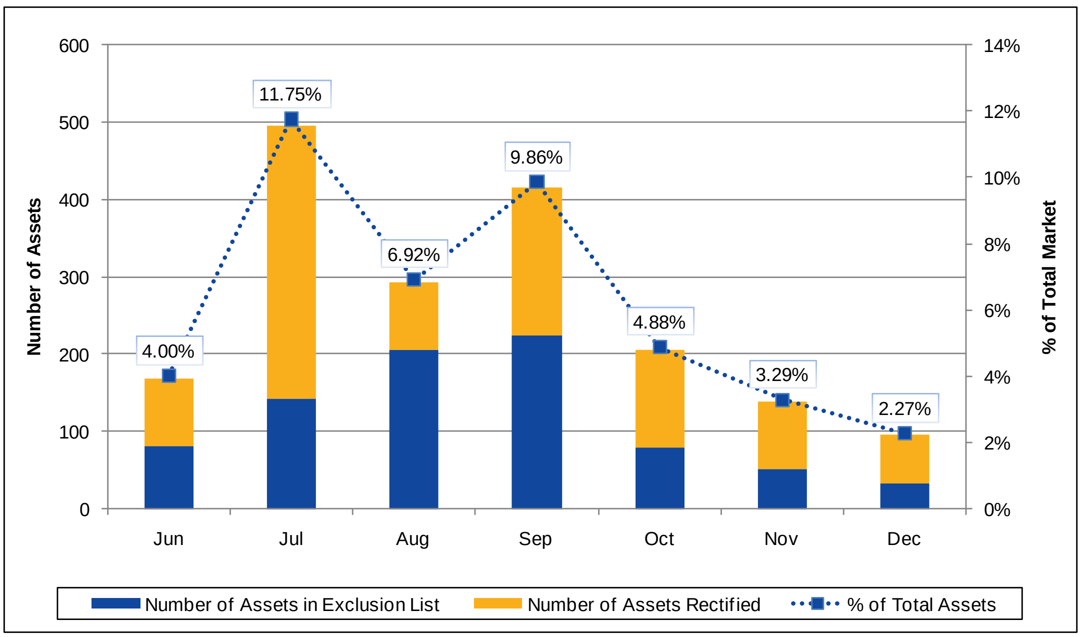

Figure 3-33: Demand-response assets on exclusion and notification lists, June to December 2010.

[125] For June 2010, an asset failed data validation if it met at least one of three criteria: its interruptions were two times its maximum load, its interruptions were two times its maximum generation, or its baseline was two times its maximum load. For July 2010 and later months, the threshold was lowered to 1.25 times any of the three parameters. There was no minimum number of intervals: if an asset's values were outside the thresholds for even a few intervals, it failed data validation.

[126] The *demand reduction value* is the quantity of demand reduced by a demand resource and measured at the end-use customer meter.

3.6.6 Demand-Response Conclusions

The transition to the Forward Capacity Market on June 1, 2010, brought several changes to the ISO demand-response programs—four programs or asset categories were retired, four new resource types were introduced, and the RTPR program and DALRP were extended. Overall, demand-resource enrollments declined with the transition to the FCM, but megawatt-hours of interruptions in 2010 were more than double 2009 levels. Payments for all demand-resource programs totaled $144 million in 2010. Capacity market payments accounted for $134 million of the total.

Participation in the DALRP increased in June—likely because of a decrease in the minimum offer price—and stayed high throughout the rest of the year. The increased activity in the DALRP has highlighted problems related to the calculation of baselines and adjusted baselines and the need for more detailed information about demand-reduction measures.

3.7 Oversight

This subsection summarizes the Internal Market Monitor's mitigation and investigation activities in 2010.

3.7.1 Market Mitigation Activities

Under *Market Rule 1*, the IMM monitors the market impact of specific bidding behavior (i.e., offers and bids) and, in specifically defined circumstances, mitigates behavior that interferes with the competitiveness and efficiency of the energy markets and daily reliability payments.

3.7.1.1 Mitigation under Market Rule 1, Appendix A, Section 5: Economic Withholding and Uneconomic Production

Economic withholding occurs when a supplier offers output to the market at a price above its full incremental costs. If the offer also is above the market price, the output is not sold. For example, during periods of high demand and high electric energy prices, all generation capacity with full incremental energy costs that do not exceed the energy price should be producing energy or supplying operating reserves through redispatch. Failing to do so would be an instance of economic withholding.

A two-part conduct-impact test for triggering mitigation is used in New England. First, supplier conduct is tested to determine whether the supplier may have attempted withholding. If the supplier fails this conduct test, a test for market impact is applied. Suppliers that have increased market prices by more than a defined threshold fail the market-impact test, and mitigation is imposed. The mitigation for economic withholding is to replace the supplier's offer with a reference level intended to represent the supplier's full incremental costs. These criteria are applied each day to all participants in constrained areas. A less-restrictive set of thresholds is applied each day to systemwide pivotal suppliers.

During 2010, no participant behavior required the application of Day-Ahead Energy Market mitigation. Ten Real-Time Energy Market mitigation events occurred. Also during the year, day-ahead NCPC was mitigated in 23 instances, and for 28 events, daily real-time NCPC payments paid to participants were retroactively mitigated. Three participants had FTR revenues, associated with eight paths, reduced by a total of $11,649 pursuant to the FTR revenue-capping provisions of *Market*

Rule 1.[127] In addition to taking these specific actions, the IMM had nearly daily discussions with individual participants concerning specific market behavior.

3.7.1.2 Resource Audits

Market Rule 1, Appendix A, Section 4.3.2, authorizes the IMM to verify *forced* (i.e., unplanned) outages. The IMM uses all available data to determine whether a plant inspection is warranted. If an inspection is appropriate, the IMM contacts both the plant management and the lead participant representing the resource to coordinate access to the plant and a visual inspection of the reported cause of the forced outage. If the results of a plant inspection suggest that the resource owner has physically withheld the resource, the ISO obtains and reviews appropriate additional information. For completed reviews showing that physical withholding has taken place, the ISO may refer that participant to FERC, as outlined in Appendix A of *Market Rule 1*.

During 2010, the IMM requested detailed plant information and operator logs for a number of cases. In each case, the IMM monitored for potential physical withholding of a resource and determined that a plant inspection was not warranted.

3.7.1.3 Cap on FTR Revenues

Market Rule 1, Appendix A, Section 8.4, authorizes the IMM to cap the revenues of FTR holders that use virtual transactions to create congestion that increases the value of the FTR path. When this occurs under the defined thresholds of Section 8.4 of Appendix A, the FTR path is "capped" to the amount that the participant originally paid for the FTR path. In 2010, the IMM capped a total of $11,649 in revenues on eight FTR paths.

3.7.2 Market Investigation Activities

The *Energy Policy Act of 2005* grants FERC broad authority to regulate manipulative or fraudulent behavior in the energy markets. FERC implemented its new authority by amending its existing regulations to prohibit any entity from directly or indirectly engaging in the following behavior in connection with the purchase or sale of electric energy or transmission services subject to its jurisdiction:

- Using or employing any device, scheme, or artifice to defraud
- Making any untrue or misleading statement
- Engaging in any fraudulent or deceptive act, practice, or course of business

Under EPAct and Section 14 of Appendix A, the IMM must make a referral to FERC if it finds a potential violation of EPAct or the market-behavior rules. While the IMM does not have to prove that a market violation has occurred, it is obligated to provide sufficient credible information to warrant further investigation by FERC.

In 2010, the IMM made one nonpublic referral to FERC, bringing the total amount of opened IMM referrals before FERC to six. No referrals were closed in 2010. The IMM and the ISO also responded to various requests from FERC for additional information in connection with the alleged market violations that were referred and other FERC activities and investigations.

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[127] *Market Rule 1*, Appendix A, Section III.A.8.4, "Cap on FTR Revenues," http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append_a.pdf.

Section 4
Forward Capacity Market

This section summarizes the 2010 activities and results associated with the Forward Capacity Market, including the FCM transition period, the first four Forward Capacity Auctions, and the two annual reconfiguration auctions (ARAs). Refer to Section 2.2 for an explanation of the structure of the FCM, the auction process, and IMM oversight.[128] The first four FCAs have cleared at the floor price and resulted in a growing surplus amount over the period. The ability of the FCA to attract and efficiently price capacity when new capacity is needed has not yet been tested.

4.1 FCM Transition Period

FCM transition payments replaced the Installed Capacity (ICAP) Market in December 2006 and continued until the 2010/2011 capacity commitment period when the FCM payments based on the auction results began. FCM transition payment rates were $3.75/kW-month from June 2008 through May 2009 and then increased to $4.10/kW-month in June 2009 through May 2010. FCM transition payments to qualifying capacity resources totaled $790,535,203 for January to May 2010. Table 4-1 summarizes the capacity requirements, the total capacity purchased, and the total payments in each transition period year.

Table 4-1
Installed Capacity Market/FCM Transition Payment

Year	Average UCAP Supply (MW)[(a)]	Annual Installed Capacity Requirement (MW)[(b)]	Total Payment ($)	ICAP Transition Payment Rate ($/kW-month)	
				Jan–May	Jun–Dec
2007	34,985	31,270	1,280,464,983	3.05	3.05
2008	36,331	32,160	1,505,257,134	3.05	3.75
2009	37,236	31,823	1,765,901,336	3.75	4.10
2010	38,563		790,535,203	4.10	

(a) UCAP stands for *unforced capacity*, the amount of installed capacity associated with a generating unit adjusted for availability.

(b) The Installed Capacity Requirement is listed in the *Forward Capacity Informational Filing* to FERC, http://www.iso-ne.com/regulatory/ferc/orders/2009/sep/er09-1424-000_9-18-09_fca_informational_filing.pdf.

4.2 Forward Capacity Auction Results

The ISO has held four Forward Capacity Auctions to date, as shown in Table 4-2.

[128] More detailed information about capacity requirements, the FCM qualification process, and qualified capacity are contained in the ISO's filings to FERC and FERC orders associated with the FCM, available at http://www.iso-ne.com/markets/othrmkts_data/fcm/filings/index.html.

Table 4-2
Forward Capacity Auctions

Auction	Commitment Period	Date of Auction
FCA #1	June 1, 2010–May 31, 2011	February 4–6, 2008
FCA #2	June 1, 2011–May 31, 2012	December 8–10, 2008
FCA #3	June 1, 2012–May 31, 2013	October 5–6, 2009
FCA #4	June 1, 2013–May 31, 2014	August 2–3, 2010

Each of the four FCAs has procured the capacity needed to meet the region's resource adequacy requirements. Table 4-3 shows that the total of existing and new qualified capacity exceeded the net Installed Capacity Requirement (NICR) (see Section 2.2.1) by 21% in FCA #1, by 32% in FCA #2, by 34% in FCA #3, and by 26% in FCA #4. Moreover, the floor price was reached in each auction because each FCA cleared capacity in excess of that necessary to meet the NICR These results are consistent with the outcome of a competitive market with excess supply.

Table 4-3
Results of Forward Capacity Auctions #1 to #4

	FCA #1	FCA #2	FCA #3	FCA #4
Total qualified (MW)	39,165	42,777	42,746	40,412
Total cleared (MW)[a]	34,077	37,283	36,995	37,501
NICR (MW)	32,305	32,528	31,965	32,127
Excess cleared (MW)[a]	1,772	4,755	5,030	5,374
Clearing price ($/kW-month)	$4.50	$3.60	$2.95	$2.95

(a) Excludes RTEG resources in excess of 600 MW.

Given the constraints of the price floor, the FCAs have performed successfully in determining capacity clearing prices that reflect robust supply and sufficient competition.[129] Consistent with the excess supply outcome, each auction cleared at its specified floor price—$4.50/kW-month in FCA #1, $3.60/kW-month in FCA #2, and $2.95/kW-month in both FCA #3 and #4. To ensure that the total capacity payment remains the same, cleared resources have the option either to prorate their obligation quantities and receive the full payment per megawatt, or to prorate their payments and retain the obligation for the full quantity of accepted capacity.[130] Prorating the capacity obligation reduces the amount of capacity the ISO procures, while prorating the payments reduces the effective prices paid for the resources.

[129] The price collar is a set of upper and lower bounds on the FCA clearing price identified for each FCA per *Market Rule 1*, Section III.13.2.7.3. The "inadequate supply" and "insufficient competition" conditions worked as designed and appropriately were not triggered; see *Market Rule 1*, Section III.13.2.7.3 and Section III.13.2.8 (May 2, 2011), http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_sec_13-14.pdf.

[130] If all resources opted to retain their full obligations, the prorated capacity payment would have been $4.25/kW-month in FCA #1 and $3.12/kW-month in FCA #2 in both capacity zones. In FCA #3, the capacity payment in the Rest-of-Pool zone would be prorated to $2.54/kW-month and to $2.47/kW-month in Maine, and in FCA #4, the capacity payment in the Rest-of-Pool zone would be prorated to $2.52/kW-month and to $2.34/kW-month in Maine. See the Forward Capacity Auction results filings at http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/index.html.

None of the auctions had local sourcing requirements (LSRs); the ISO determined that each potential import-constrained area had sufficient existing capacity. Maine was modeled as an export-constrained capacity zone in the four auctions; FCA #1 had a 3,855 MW maximum capacity limit (MCL); FCA #2 had an MCL of 3,395 MW; FCA #3 had an MCL of 3,257 MW; and FCA #4 had an MCL of 3,187 MW.

4.3 Qualification of Resources

A large amount of capacity with diverse ownership participated in all four auctions. Table 4-4 summarizes the qualified existing capacity included in each FCA.[131] These values do not include delist bids or any new capacity resources being treated as existing resources in FCA #1.[132]

Table 4-4
Qualified Existing Capacity
Participating in the Forward Capacity Auction (MW)

Type of Resource	FCA #1	FCA #2	FCA #3	FCA #4
Generation	31,447	31,401	32,636	32,718
Imports	1,269	1,311	2,164	1,356
Demand resources	1,990	2,978	2,845	3,137
Total	**34,705**	**35,690**	**37,645**	**37,211**

Table 4-5 shows qualified new capacity that participated in the auctions. Qualified capacity from new resources increased 59% from the first to the second auction. Between FCA #2 and FCA #3, the amount of new capacity participating fell 28%; between FCA #3 and FCA #4, new capacity decreased 37%. The increase in new capacity in FCA #2 was largely the result of out-of-market (OOM) capacity entered by the peaking units that were successful bidders in the state of Connecticut's request for proposals (RFP) for peaking units.

Table 4-5
Qualified New Capacity Participating
in the Forward Capacity Auctions (MW)

Type of Resource	FCA #1	FCA #2	FCA #3	FCA #4
Generation	2,353	3,299	2,830	947
Imports	658	2,613	1,751	1,244
Demand resources	1,449	1,176	519	1,010
Total	**4,459**	**7,088**	**5,100**	**3,201**

131 The qualified resource numbers for FCA #3, as reported in the ISO presentation to the Planning Advisory Committee, is available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2009/nov182009/fca3_results.pdf.

132 For FCA #1 only, qualified new capacity projects had the option to participate in the market as existing resources.

4.4 Cleared Capacity and Delistings

The FCA continues to secure more capacity than needed to meet reliability. The percentage of demand resources has grown slowly and is at 9% of all resources that cleared in the auction. The amount of resources delisting has remained low; however, this may change if the floor price is removed. Most new generation added has been out of market, except for a large repowering that is treated as new generation under the FCM rules

Table 4-6
Capacity Cleared in Auctions (MW and Percentage of Total)

Type of Resource	FCA #1		FCA #2		FCA #3[a]		FCA #4[b]	
Generation	30,865	(90%)	32,207	(86%)	32,228	(87%)	32,247	(86%)
Existing	30,825		31,050		30,558		32,103	
New	40		1,157		1,670		144	
Imports	934	(3%)	2,298	(6%)	1,900	(5%)	1,992	(5%)
Existing	934		769		1,083		1,161	
New	0		1,529		817		831	
Demand resources[c]	2,279	(7%)	2,778	(8%)	2,868	(8%)	3,261	(9%)
Existing	1,419		2,330		2,559		2,746	
New	860		448		309		515	
Total	**34,077**		**37,283**		**36,996**		**37,501**	

(a) FCA #3 results are from Attachment A of the *Forward Capacity Auction Results Filing* to FERC, as contained in the spreadsheet available at http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/ccp13/fca13/fca3_monthly_ob_v2.xls.

(b) FCA #4 results are from *Forward Capacity Auction 2013-2014 Totals Flow Diagram,* available at http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/ccp14/fca14/fca_4_totals_flow_diagram.pdf. This number is not adjusted for the RTEG limit of 600 MW.

(c) The 2,778 MW total for demand resources for FCA #2 reflects the 600 MW RTEG cap. An additional 159 MW of RTEG above the cap also was procured, making the total demand resources 2,937 MW. The 2,868 MW of demand resources in FCA #3 also reflects the 600 MW RTEG cap. An additional 30 MW of RTEG above the cap also was procured, making the total demand resources 2,898 MW.

4.4.1 Resources Cleared by Location

As noted, none of the four auctions modeled any import-constrained zones because preauction screens showed that no potential import-constrained zones needed additional capacity to meet reliability requirements.[133] Each of the auctions cleared more capacity in the CT and NEMA load zones than needed to meet their local sourcing requirements. The Maine export constraint had no price separation when the auction cleared at the floor price, even though cleared capacity in FCA #3 and FCA #4 exceeded Maine's maximum capacity limit. Price separation did not occur because the excess capacity in Maine remained at the floor price, so continuing the auction and reducing the excess capacity were not possible. Table 4-7 shows the breakdown by location for the three FCAs.

[133] However, in FCA #3, existing capacity in Boston would have been insufficient to meet the more stringent Transmission Security Analysis criteria had Salem Harbor been allowed to delist as requested; see Section 4.4.5.

Table 4-7
Resources Cleared by Location (MW)

	FCA #1			FCA #2			FCA #3[a]			FCA #4[b]		
	CT	NEMA	Maine	CT	NEMA	Maine	CT	NEMA	Maine	CT	NEMA	Maine
Cleared Capacity	8,037	3766	3,517	9,159	3,847	3,538	9,237	3,703	3,598	9,239	3,835	3,663
LSR	7,017	2,246	3,855 (MCL)	6,817	2,016	3,395 (MCL)	6,640	2,019	3,257 (MCL)	7,419	2,957	3,187 (MCL)
Excess Capacity	1,020	1,520		2,342	1,831		2,597	1,684		1,820	878	

(a) FCA #3 results are from Attachment A of the *Forward Capacity Auction Results Filing* to FERC, as contained in the spreadsheet available at http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/ccp13/fca13/fca3_monthly_ob_v2.xls. In FCA #3, most new capacity was from generation in the SEMA load zone.

(b) Information about the LSRs for FCA #4 is available in http://www.iso-ne.com/regulatory/ferc/filings/2010/may/er10-___-000_05-04-10_icr_2013-2014.pdf. Cleared capacity is from Attachment A of the *Forward Capacity Auction Results Filing* to FERC, as contained in the spreadsheet available at http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/ccp14/fca14/index.html. Maine totals do not include 366 MW of imports from New Brunswick.

Figure 4-1 shows the distribution of total cleared resources by load zone, and Figure 4-2 shows the distribution of new cleared resources by load zone.

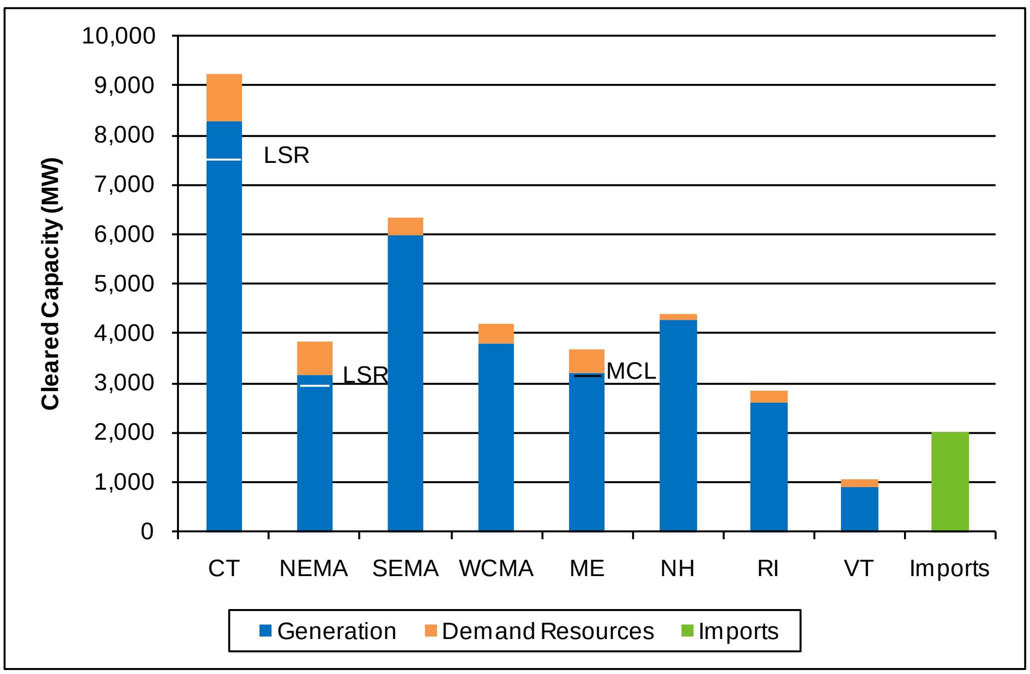

Figure 4-1: FCA #4 auction results for total cleared resources.

Note: Import-constrained areas, which have insufficient local capacity, are assigned a local sourcing *requirement* (LSR). Export-constrained areas, which have a surplus of capacity, are assigned a *maximum capacity limit* (MCL).

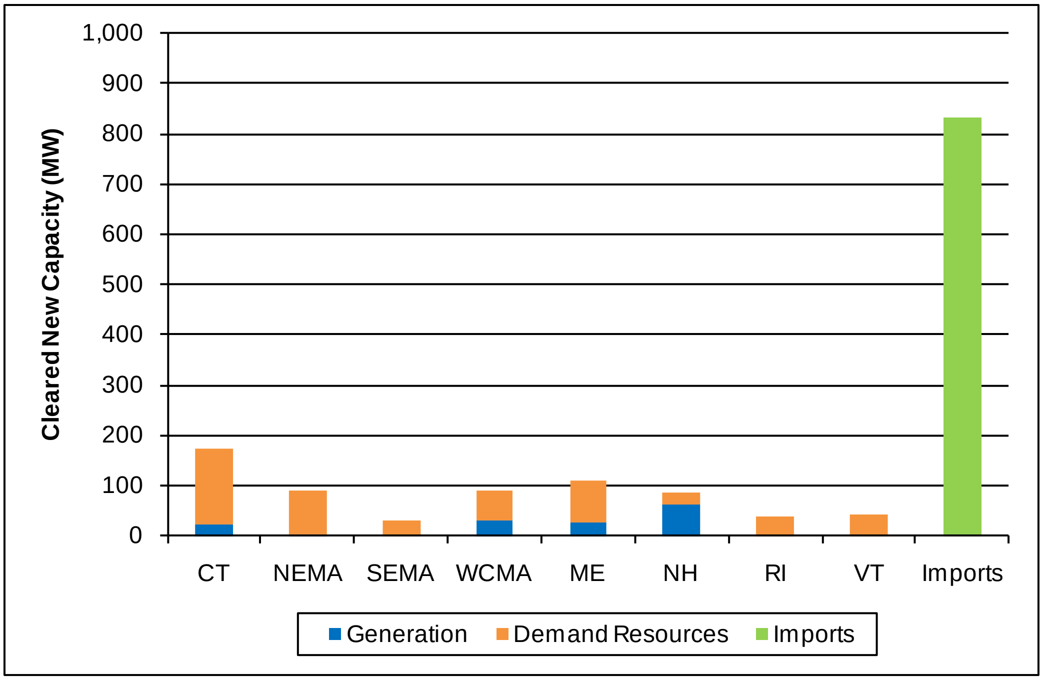

Figure 4-2: FCA #4 auction results for new cleared resources.

4.4.2 Imports

Imports to the ISO may come from the Hydro-Québec, the New York ISO (NYISO), and New Brunswick systems. As shown in Table 4-8, imports represented 5.1% of the cleared capacity in FCA #3, and 5.3% in FCA #4.[134] In FCA #4, Hydro-Québec had the largest amount of qualified imports, but NYISO cleared more. All 948 MW of qualified imports from NYISO cleared the auction, while only 678 MW of the 1,075 MW that qualified cleared from Hydro-Québec. In FCA #4, 831 MW of new import capacity cleared, compared with 1,161 MW of existing imports.

Table 4-8
Sources of Qualified and Cleared Imports (MW)

	FCA #1		FCA #2		FCA #3		FCA #4	
System	**Qualified**	**Cleared**	**Qualified**	**Cleared**	**Qualified**	**Cleared**	**Qualified**	**Cleared**
Hydro-Québec	1,167	200	727	662	1,886	679	1,075	678
NYISO	734	734	2,842	1,352	1,729	921	948	948
New Brunswick	26	0	355	284	300	300	576	366
Total	**1,926**	**934**	**3,924**	**2,298**	**3,915**	**1,900**	**2,559**	**1,992**

[134] See the ISO's informational FERC filings for FCA #1 (November 6, 2007), FCA #2 (September 9, 2008), and FCA #3 (July 7, 2009) at http://www.iso-ne.com/markets/othrmkts_data/fcm/filings/index.html, and for FCA #4 (August 30, 2010) at http://iso-ne.com/regulatory/filings/2010/aug/index.html.

4.4.3 Demand Resources

A notable feature of the first four auctions is the amount of capacity from demand resources that qualified and cleared. As shown in Table 4-6 above, demand resources accounted for 7% to 9% of the cleared capacity.

As shown in Figure 4-3, in all four auctions, the majority of cleared demand capacity came from active demand resources (RTDR or RTEG), and the rest was from passive demand resources (on-peak and seasonal demand resources).[135] In FCA #4, 2,051 MW came from active demand resources, and 1,298 MW came from passive demand resources. More capacity from demand resources qualified in FCA #4 than in FCA #3 or FCA #1; qualified amounts were almost identical in FCA #2 and FCA #4.

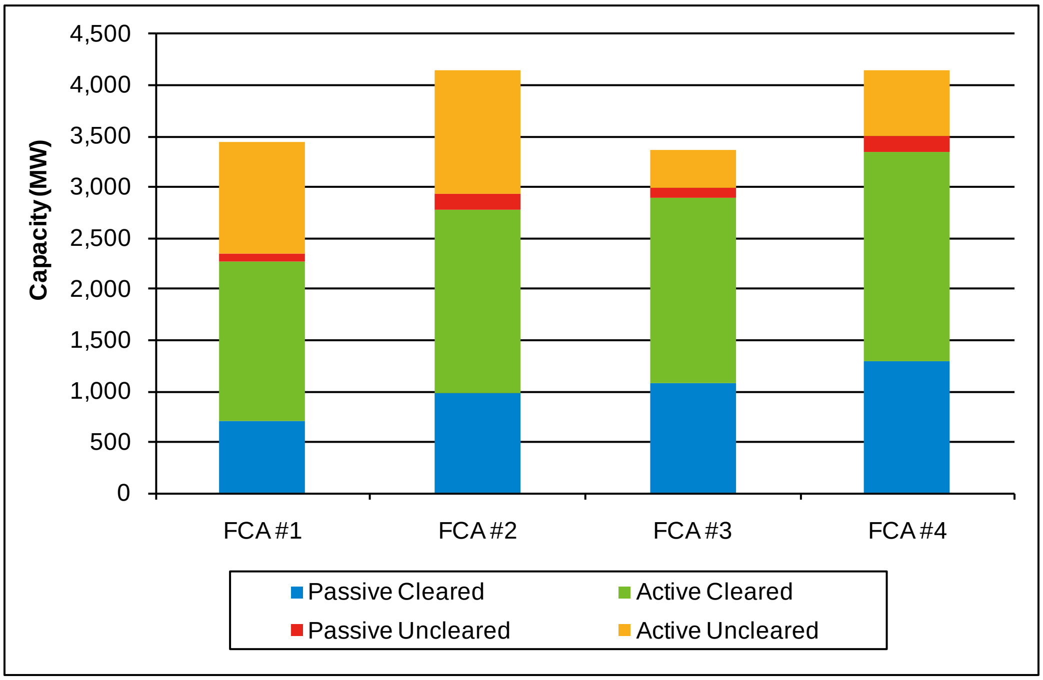

Figure 4-3: Auction results for qualified demand resources.

Note: Data are from Attachment A of the *Forward Capacity Auction Results Filing* to FERC, as contained in the spreadsheets available at http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/.

Table 4-9 provides a breakdown of the auction results by type of demand resource and identifies the amount of new resources. More capacity from demand resources cleared in FCA #4 than in the previous three auctions.

135 Real-time emergency generation is treated as a demand resource because it is on the retail side of the wholesale meter.

Table 4-9
Auction Results for Qualified Demand Resources by Type (MW)

Demand Resource	Type of Demand Resource	FCA #1	FCA #2	FCA #3	FCA #4
Existing cleared	Active	999	1,614	1,727	1,794
	Passive	420	716	862	1,040
New cleared	Active	580	186	98	257
	Passive	280	262	211	258
Existing delisted	Active	570	648	256	419
	Passive	1	0	1	32
New uncleared	Active	522	571	113	232
	Passive	66	157	96	115
Total cleared		**2,279**	**2,778**	**2,898**	**3,349**
Total uncleared/ delisted		**1,159**	**1,375**	**466**	**798**

4.4.4 Out-of-Market and In-Market New Resources

Out-of-market resources, which participate in the FCM at prices below their costs, include certain new resources with offer prices less than 0.75 times the cost of new entry (CONE), new self-supplied resources, and capacity under ISO-issued RFPs.[136] Figure 4-4 shows the new in-market and OOM capacity that cleared in the first four FCAs. In FCA #4, cleared OOM new entry accounted for 37%, or 548 MW, of the 1,490 MW of cleared new capacity. Most new generation that has cleared has been out of market. The large amount of new generation clearing in FCA #3 was not a new facility but investment in an existing facility defined as new generation under the FCM rules. New demand resources have been both in market and out of market. The large amount of new imports results from the way imports are defined currently in the FCM. Most imports currently are classified as new resources; FERC has approved rule changes that will change the classification of new imports to existing resources for FCA #7 or FCA #8.[137]

[136] The CONE is used to (1) establish the starting price for each FCA, (2) set thresholds for reviewing delist bids to deter the exercise of market power, (3) set initial pricing for some reconfiguration auctions, and (4) determine pricing when the supply is inadequate and competition is insufficient. The CONE is derived from the capacity clearing price from previous FCAs, except for FCA #1, where it was administratively set.

[137] FERC, *Order on Paper Hearing and Order on Rehearing* Docket Nos. ER10-787-000, EL10-50—000, EL10-57-000, EL10-787-004, EL10-50-002, EL10-57-002 (April 13, 2011), http://www.iso-ne.com/regulatory/ferc/orders/2011/apr/fcm_%20redesign_order_april_13_2011.pdf.

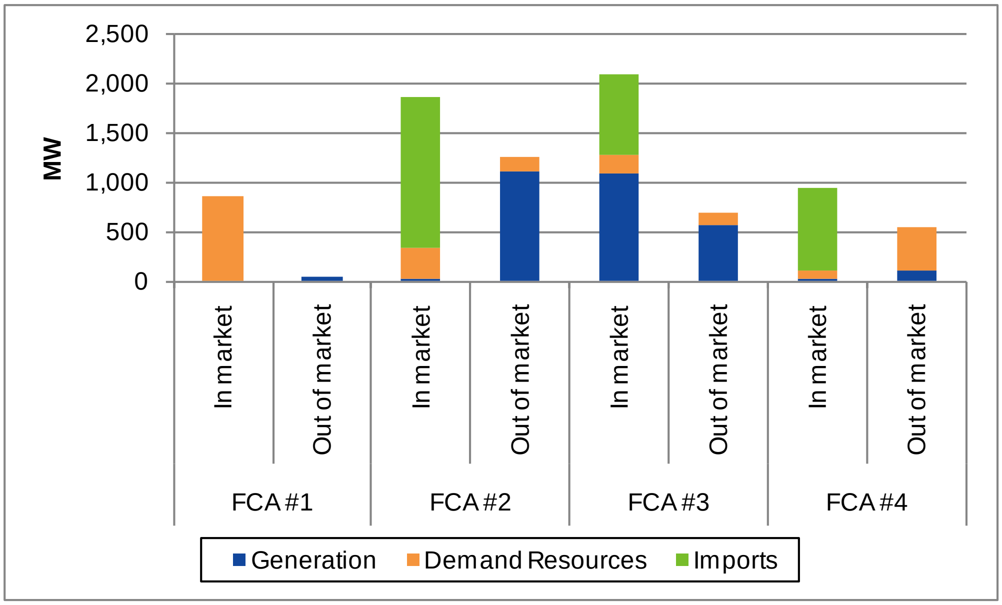

Figure 4-4: Cleared new, in-market, and out-of-market capacity, FCA #1, FCA #2, FCA #3, and FCA #4 (MW).

Figure 4-4 shows, with the exception of FCA #3, that most new in-market resources are either imports or demand resources. In FCA #3, the approximately 1,100 MW of in-market generation was not new generation but investment in an existing generating station. Thus, the FCM has not attracted new, in-market generation. Given current surpluses, that new in-market generation has not entered the market is logical because owners of existing resources would make additional investments in uprates, if economic, before building new units. However, even with the possibility that some of the region's older resources retire and some of its nuclear units reach the end of their licenses, the ability of the market to attract timely new in-market generator entry remains largely untested.

4.4.5 Delisted Capacity Resources

Table 4-10 shows the accepted delist bids from existing resources. In all four FCAs, an insufficient amount of capacity was willing to leave the market at prices at or near the floor price. In FCA #1, most of the delisted capacity came from generation resources, which requested to delist 1,300 MW. The ISO approved 970 MW and rejected 330 MW: the 162 MW Norwalk Harbor unit #1 and 168 MW Norwalk Harbor unit #2. These delist bids were rejected because the results of the ISO's reliability analysis indicated that the generators would be needed for reliability. However, Norwalk Harbor #2 was released and allowed to delist before the start of the commitment period because a change in the load forecast meant that the unit was no longer needed for reliability. After being allowed to delist, the generator took on a capacity obligation of 167 MW through bilateral transactions.

Table 4-10
Delisted Existing Resources by Type (MW)

Resource Type	FCA #1	FCA #2	FCA #3[(a)]	FCA #4
Generation	622 (64%)	350 (39%)	543 (32%)	675 (55%)
Demand resources	296 (31%)	489 (55%)	257 (15%)	451 (38%)
Import	51 (5%)	51 (6%)	910 (53%)	102 (8%)
Total delisted	**970**	**890**	**1,710**	**1,228**

(a) The data for FCA #3 do not include 6.6 MW of administrative permanent delist bids because of a failure of the resource to submit an updated measurement and verification plan pursuant to the tariff.

Demand resources dominated the delisting requests in FCA #2, accounting for 489 MW out of the total. Delist requests from all resource types totaled 890 MW, all of which were approved. Thirteen generation units made full delist requests, totaling 183 MW. No delist bids were rejected in FCA #2.

In FCA #3, existing import capacity accounted for the largest proportion of delisted capacity (53%). The ISO approved 1,710 MW of existing resources to delist. Dominion Resources sought to delist the entire Salem Harbor station, which consists of four resources: three coal units and one oil unit for a total of 743 MW. The IMM reviewed these bids according to *Market Rule 1* and submitted revised delist bids to FERC for approval. After FERC review, delist bids were included in FCA #3 for all four units at Salem Harbor station. Two of the units, Salem Harbor #1 (82 MW) and Salem Harbor #2 (80 MW), cleared in the auction (i.e. the auction price fell below their delist bid) and delisted. Salem Harbor #3 (150 MW) and Salem Harbor #4 (431 MW), totaling 581 MW, would have delisted, but pursuant to the FCM rules, they were retained to meet reliability needs in the greater Boston area.[138] These resources received their bid price, rather than the auction-clearing price.

In FCA #4, existing generation capacity accounted for the largest proportion of delisted capacity (55%). The ISO approved 1,228 MW of existing resources to delist, and 1,190 MW were rejected. Delist bids for Salem Harbor #3 and #4 (587 MW total) were submitted and rejected for reliability reasons, as they had been in the previous auction.[139] A delist bid from the 604 MW Vermont Yankee nuclear generating station also was rejected for reliability reasons. While the delisted resources helped reduce the excess capacity, the floor price remained. Most of the delist requests were dynamic bids submitted below 0.8 times CONE.

Table 10 shows that demand resources have delisted at a far greater percentage than generating resources. Generator delists range up to 675 MW on a base of approximately 32,000 MW, or in the 2% range, while demand-resource delisting have ranged up to 451 MW on a base of about 2,800 MW, or nearly 16%.

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[138] See the testimony of Stephen J. Rourke, *Forward Capacity Results Filing*, Attachment D, FERC Docket No. ER10-___-000 (October 30, 2009), http://www.iso-ne.com/regulatory/ferc/filings/2009/oct/er10-___-000_10-29-09_fca_3_results_filing.pdf. His testimony is redacted but summarized on page 10 of the filing.

[139] The difference between the 581 MW delist in FCA #3 and 587 MW delist in FCA #4 is due to a change in qualified capacity for Salem Harbor #4.

Figure 4-5 shows accepted and rejected delist requests. In all three auctions with rejected delist bids, the capacity from rejected delist bids was substantially below excess capacity, and the rejection had no impact on clearing prices. Most of the delist requests in each of the auctions were dynamic bids. The static delist bids were the second largest category. It is not surprising that many resources chose dynamic delist bids. Dynamic delist bids do not require any review by the IMM, and since the threshold for dynamic delist bids is above the floor price, resources that wanted to leave the market for one year could be reasonably certain, given the surplus on the system, that the auction would reach the dynamic delist level.

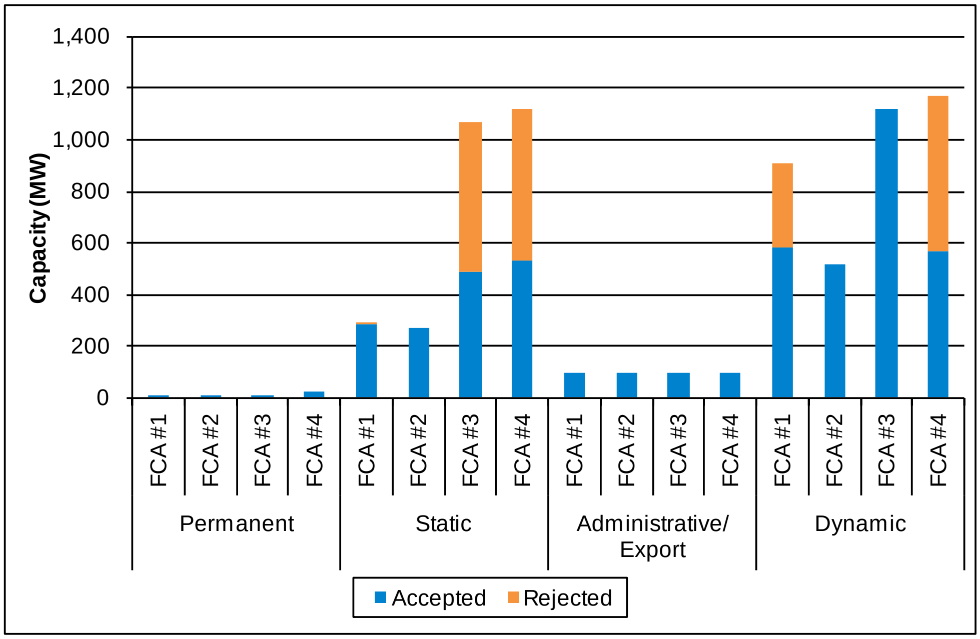

Figure 4-5: Requests for various types of capacity delistings, Forward Capacity Auctions.

4.4.6 Generation with No Capacity Supply Obligation

Table 4-11 shows the number of generators in each month after the introduction of FCM that had no capacity supply obligation, along with their total seasonal claimed capability.[140] The reasons that these generators had no CSO vary. Some delisted in FCA #1, some are new generators unable to participate in FCA #1, and several of the generators obtained a CSO in FCA #1 but traded it away either in a reconfiguration auction or bilaterally.

[140] Settlement-only generators are not included.

Table 4-11
Generators with No Capacity Supply Obligation, June to December 2010

Month	Number of Generators	Total Seasonal Claimed Capability (MW)
Jun	28	224.604
Jul	27	134.974
Aug	26	269.735
Sep	27	275.592
Oct	26	287.303
Nov	25	280.373
Dec	25	280.373

Assets without a CSO may offer into the Day-Ahead Energy Market or self-commit in the Real-Time Energy Market. However, the ISO may request that a generator with no capacity supply obligation operate for reliability even if it did not clear or self-commit.

In addition, participants can assign forward-reserve megawatts to a resource without a CSO. Forward-reserve assignments are made during the reoffer period, and generators without a CSO but assigned to provide forward reserve must be offered into the Real-Time Energy Market.[141] Seventeen of the generators that had no CSO were regularly assigned to provide forward reserve.

4.5 Capacity Supply Curves

Figure 4-6 depicts the supply curves from the four auctions.[142] These curves reflect the offer prices from new resources and delist bid prices from existing resources revealed as resources that exited the auction as the descending clock progressed.[143] The lower portions of the supply curves (not shown on the chart) are flat because this is where the clock stopped. Therefore, the supply curve is not revealed below the floor price. However, the remaining capacity includes both new and existing resources. That these resources remained in the auction indicates that the cost of new entry for some new resources and the going-forward costs for many existing resources are at or below the floor price.

[141] *Market Rule 1*, Section III.9.5.1, “Assignment of Forward Reserve MWs to Forward Reserve Resources,” 117, http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_sec_1-12.pdf.

[142] These supply curves are constructed from the results of FCA #1, FCA #2, and FCA #3, which are available at http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/ccp13/fca13/fca3_monthly_ob_v2.xls.

[143] These supply curves do not reflect the caps on import resources because of the external interface limits and the 600 MW cap on RTEG resources.

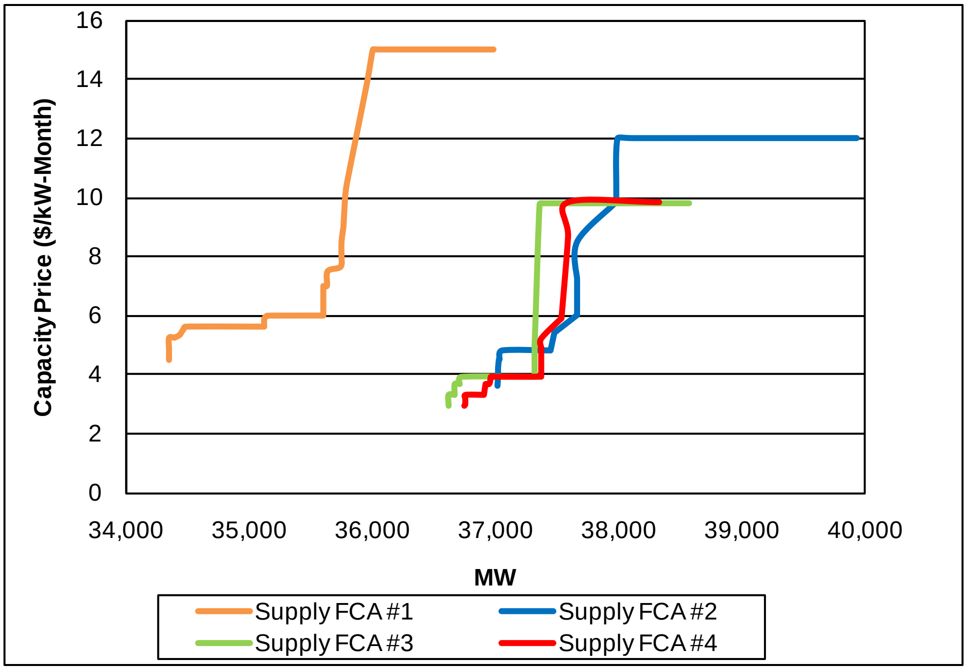

Figure 4-6: Supply curves for Forward Capacity Auctions.

4.6 FCM Payments and Charges

Table 4-12 shows the payments made since June 2010 to generator, demand, and import resources for their capacity during the obligation month. The table shows the initial supply credit paid for the CSO, which can then be adjusted based on computed values for peak energy rent (PER) and resource performance (see Section 2.2.5). The ISO's participation in reconfiguration auctions, when it is necessary to buy additional capacity because of an increase in the ICR or to sell capacity because of a decrease in ICR, also can have an impact on the supply credit; the sale of excess CSOs will reduce the supply credit, while the purchase of additional CSOs will increase the supply credit. Additional penalties and credits can be charged or earned on the basis of resource availability during shortage events (generator and import resources) or for performance during dispatch events and performance hours (demand resources). Resources retained for reliability can earn additional credits.

The PER adjustment is over 13% in most months. This adjustment was much larger than anticipated in the design of the FCM. FERC has approved rule changes that will reduce this amount by changing the fuel used to calculate the PER strike price from natural gas to oil.[144]

[144] FERC, *Order Accepting Tariff Provisions in Part, and Rejecting Tariff Provisions in Part*, Docket No. ER11-2427-000 (February 17, 2011), http://www.iso-ne.com/regulatory/ferc/orders/2011/feb/er11-2427-000_2-17-11_partial_accept-reject_tariff_rev.pdf.

Table 4-12
Monthly FCM Payments and Charges in 2010, Rest-of-Pool Capacity Zone (MW and $)[(a)]

Month	CSO MW	Supply Credit	PER Adjustment	Excess Demand-Resource Penalties	Reliability Credit	Total Payment
Jun	32,704	$137,115,382	−$8,354,906	−$520,682	$282,690	$128,522,485
Jul	32,704	$137,115,382	−$10,019,246	−$164,084	$282,690	$127,214,743
Aug	32,704	$137,115,382	−$14,125,533	$0	$282,690	$123,272,540
Sep	32,704	$137,115,382	−$16,598,236	$0	$282,690	$120,799,837
Oct	32,853	$137,760,209	−$19,017,941	$0	$282,690	$119,024,957
Nov	32,850	$137,751,864	−$18,278,258	$0	$282,690	$119,756,296
Dec	32,909	$137,718,375	−$18,020,748	$0	$282,690	$119,980,317

(a) These data are subject to resettlement

4.7 Reconfiguration Auctions and Bilateral Transactions, 2010/2011 Capacity Commitment Period

This section covers transactions for the 2010/2011 Capacity Commitment Period. It includes information about the reconfiguration auctions and bilateral transactions that participants use to transfer capacity supply obligations.

Participants can transfer and acquire capacity supply obligations through bilateral transactions and reconfiguration auctions.[145] Both bilateral transactions and auction trades can be for periods of either one month or the entire one-year capacity commitment period, and volumes exchanged in monthly bilateral trades and the monthly reconfiguration auctions vary from month-to-month.

Reconfiguration auctions serve two purposes. They allow participants to transfer and acquire capacity supply obligations, and, in the case of the third annual reconfiguration auction for the 2010/2011 Capacity Commitment Period, they allow the ISO to make adjustments to capacity requirements and to submit demand bids on behalf of resources that have had “significant decreases” in claimed capability.[146]

Table 4-13 shows capacity supply obligations transferred in the two annual reconfiguration auctions and bilateral trades held for the 2010/2011 capacity period. A participant with a cleared demand bid transfers its CSO, while a participant with a cleared supply offer acquires an obligation. The clearing price for the second annual reconfiguration auction for this period was $1.50/kW-month, and the clearing price for the third auction was $1.43/kW-month, both well below the FCA #1 floor price of $4.50/kW-month.[147] For the 2010/2011 annual capacity period, participants had only one window, coincident with the third annual reconfiguration auction, for entering annual bilateral trades. A total

[145] RTEGs cannot participate in reconfiguration auctions. They only can acquire CSOs from other RTEGs, not from any other resource types, in bilateral trades. Capacity imports can only acquire CSOs from other imports on the same path.

[146] *Market Rule 1*, Section III.13.4.2.1.3, “Adjustment for Significant Decreases in Capacity,” http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_sec_13-14.pdf.

[147] Only the second and third reconfiguration auctions were held for the 2010/2011 commitment period. A first auction and reconfiguration auction were not scheduled.

of 960 MW was transferred in annual bilateral trades at an average price of $2.798/kW-month. The low prices in both the reconfiguration auction and the bilateral trades were likely caused in part by the surplus capacity available from resources that had prorated their CSOs. It indicates that the cost of providing capacity is low from a resource that intends to operate in the energy market.

Table 4-13
Annual Reconfiguration Auctions and Bilateral Trades for 2010/2011 Capacity Period, Clearing Prices and Quantities

Auction	Annual Reconfiguration Auctions		Annual Bilateral Trades (June 1, 2010—May 31, 2011)	
	Demand Bids and Supply Offers Cleared (MW)	Clearing Price ($/kW-month)	Trades (MW)	Average Trade Price ($/kW-Month)
Second ARA	198	$1.50		
Third ARA	444	$1.43	960	$2.60

Table 4-14 shows monthly reconfiguration auction and bilateral trade information. Reconfiguration auctions have not yet taken place for all months in the 2010/2011 delivery period. Auction clearing prices ranged from $0.76/kW-month to $2.25/kW-month. Monthly bilateral trade volumes have ranged from 81 MW (for the June 2010 commitment month) to 264 MW (for January 2011). Prices have ranged from $2.01/kW-month to $2.89/kW-month.

Table 4-14
Monthly Reconfiguration Auctions and Bilateral Transactions Clearing Prices and Quantities, 2010

Obligation Month	Monthly Reconfiguration Auctions		Bilateral Transactions	
	Cleared CSO MW	Auction Clearing Price ($/kW-Month)	Traded CSO MW	Average Trade Price ($/kW-Month)
Jun	75	$1.99	81	$2.57
Jul	58	$2.25	117	$2.59
Aug	95	$2.19	117	$2.89
Sep	86	$1.96	118	$2.83
Oct	140	$0.98	114	$2.01
Nov	227	$0.87	151	$2.01
Dec	179	$1.20	209	$2.55

Bilateral transactions are between two specific resources. For the 2010/2011 Capacity Commitment Period, participants had only one opportunity for entering annual bilateral trades, coincident with the third annual reconfiguration auction.[148] A total of 960 MW were transferred in annual bilateral trades at an average price of $2.798/kW-month.

In annual and monthly bilateral transactions, demand-response resources have acquired CSOs from other demand-response resources, and generation resources have acquired CSOs from other generation resources, from demand-response resources, and from import resources. In the reconfiguration auctions, all three resource types have cleared demand bids (transferring CSOs), while only generation and ISO supply offers have cleared (acquiring CSOs).[149] This has resulted in a decrease of 375 MW of obligations held by demand resources and a decrease of 599 MW of obligations held by import resources. Table 4-15 shows CSO megawatts transferred between resource types.

Table 4-15
CSOs Transferred from Demand and Import Resources to Generation Resources and ISO Supply Offers (MW)

	Demand Resources to Generation[(a)]	Imports to Generation[(a)]
Annual bilaterals	314	445
Second ARA	25	80
Third ARA	37	74
Total	376	599

(a) In the annual reconfiguration auctions, some megawatts were cleared by ISO supply offers.

[148] For future capacity periods for which two annual reconfiguration auctions are held, there will be three annual bilateral windows (two with the second ARA, one with the third ARA). For capacity periods with three annual reconfiguration auctions, there will be five annual bilateral windows (two each with the first ARA and second ARA, and one with the third ARA).

[149] According to *Market Rule 1,* Section 13.4.3, "ISO Participation in Reconfiguration Auctions," Where more capacity than needed is obligated, the ISO may submit supply offers in subsequent ARAs to release the excess capacity. In any case, the ISO must submit supply offers as appropriate in the third annual reconfiguration auction for a capacity commitment period to release the excess capacity. See http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_sec_13-14.pdf.

Section 5
Forward Reserve Market

As shown in this section, the results of the two forward-reserve auctions conducted in 2010—in April, for summer 2010, and in August, for winter 2010/2011—are consistent with competitive outcomes. It details the reasons for an IMM recommendation that the FRM threshold price be calculated on a daily fuel-price index, rather than the current monthly index. A description of the Forward Reserve Market mechanics is contained in Section 2.3.1. Section 3.4.11 has information on real-time reserve pricing. The data appendix, Section 8, contains additional information on the product offers for both forward-reserve auctions.

5.1.1 Locational Forward Reserve Market Auction Results

Table 5-1 shows the results of the locational forward-reserve auctions. For the summer 2010 and winter 2010/2011 auctions, the Connecticut zone had a surplus of offers and cleared below the cap. External reserve support was sufficient to meet the requirements in both the NEMA/Boston and SWCT zones. Offers for TMOR were submitted and cleared in Southwest Connecticut. The total amount paid for forward reserve in 2010 was $113.4 million, a decrease from $144.1 million in 2009.

Table 5-1
Results of Locational Forward-Reserve Auctions ($/kW-Month)

Reserve Zone	Reserve Category	Summer 2009	Summer 2010	Winter 2009/2010	Winter 2010/2011
Systemwide	TMNSR	$6.30	$5.95	$6.08	$5.50
Systemwide	TMOR	$0	$5.95	$0	$5.50
SWCT	TMOR	$14.00	$13.90	$14.00	$6.02
CT	TMOR	$14.00	$13.90	$14.00	$6.02
NEMA/Boston	TMOR	$0	$0	$0	$0

The results of the 2010 summer FRM auction for the CT reserve zone indicate a performance appropriate to the observed supply and demand conditions. The auction surplus was only 36 MW, or 2.94% of the 1,225 MW requirement. The clearing price was $13.90/kW-month, only 0.7% lower than the price cap. For the reasons described below, this outcome is consistent with a competitive outcome and is appropriate for the supply and demand conditions observed.

The IMM conducted additional analysis of the 2010 summer auction results with a focus on the CT reserve zone to better understand the prevailing market dynamic and opportunities for strategic behavior. The analysis found the following:

- The market is concentrated despite the gradual increase in the number of participants. The largest supplier in the auction had approximately 40% of the supply in CT. However, significant new entry is expected in the near future, suggesting that there are no barriers to entry.

- The IMM analyzed the strategic behavior of participants in the FRM auction and the impact of that behavior on the results of the auction. The analysis evaluated the profit-maximizing

> strategies of the bidders in the market given the market design and structure. Consistent with the market design, the analysis assumes that bidders act simultaneously, choosing a strategy that maximizes individual profit given each bidder's best guess about what other market participants will do. Each market participant has complete information about his payoff function, and each is aware of the available capacity supply. The results of the analysis indicate that no market participant has incentive to withhold from the auction; the large suppliers and smaller suppliers gain most by offering all their available capacity into the auction.

In the winter 2010/2011 auction, the number of participants in the auction rose and the reserve requirements decreased for the three local reserve zones. These two factors have increased competition, as seen through lower clearing prices in all reserve zones.

5.1.2 Forward Reserve Market Threshold Price

The FRM requires resource owners to select and assign resources to meet their FRM obligations by offering energy into the real-time market at a price at or above the FRM threshold price. The threshold price is set with the expectation that the systemwide LMP will exceed the threshold price between 2% and 3% of the time.[150] At the beginning of each month, the existing design calculates a FRM threshold price applicable to resource assignments in the month. The FRM threshold price is not updated during the month. If fuel prices within a month vary substantially from the index used to set the FRM threshold price, the difference between a resource's actual marginal costs, as reflected in its reference price, and the FRM threshold price can become large.

Figure 5-1 summarizes this risk using data between October 1, 2006 (major changes to the FRM were implemented on that date), and May 12, 2010. The graph shows that the use of a monthly FRM threshold price rather than a daily threshold price, creates a significant energy market opportunity cost risk, or alternatively, mitigation risk.

[150] Appendix A of *Market Rule 1* (http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append_a.pdf) does not exempt such resources from mitigation. It is inappropriate for resources with costs significantly below the FRM threshold price to be assigned an FRM obligation, and mitigation would be appropriate in that case. This has happened very rarely in practice.

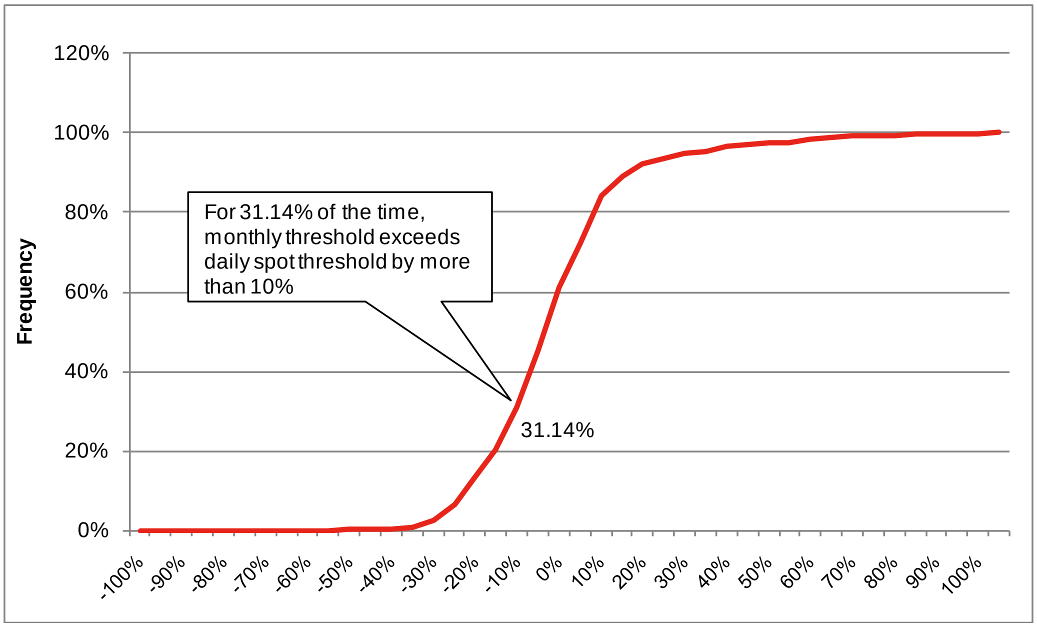

Figure 5-1: Distribution of dollar difference between monthly and daily threshold prices, October 1, 2006 to May 12, 2010.

In Figure 5-1, the horizontal axis measures the percentage difference between an FRM threshold based on a monthly fuel index and one based on a daily fuel index. A negative number means that the fuel price has declined since the start of the month and that a threshold price set daily would be below the monthly threshold price by the amount on the axis. The point called out in the graph shows that the daily threshold price would have been below the actual (monthly) FRM threshold price by at least 10% more than 31.14% of the time.

The IMM recommends that the FRM threshold price be calculated on a daily fuel-price index. A possible drawback with using the same-day fuel-price index is that the threshold price could not be published in advance of the 6:00 p.m. bidding deadline (reoffer period) for the next day. The gas price indices are published between 3:00 p.m. and 6:00 p.m. While the prices usually are available shortly after 3:00 p.m., enough publication uncertainty exists that the ISO cannot collect the data until approximately 6:00 p.m. Oil prices are published later but have much less volatility. An alternative approach would be to use the fuel prices from the day before. This introduces a one-day lag in the fuel prices but provides suppliers a known threshold price. Analysis of historical data suggests that the difference is statistically minimal. Either approach would provide an improvement over the current methodology.

Section 6
Regulation Market

This section presents data about the participation, outcomes, and competitiveness of the Regulation Market in 2010. Section 2.4 summarizes the function and operation of this market.

NERC has set the Control Performance Standard 2 (CPS 2) at 90% for the New England Balancing Authority Area.[151] CPS 2 is the primary measure for evaluating control performance and area control error (see Section 2.4). The ISO seeks to maintain CPS 2 within the range of 92 to 97%. The ISO has continually met its more stringent, self-imposed CPS 2 targets. For 2010, the ISO achieved a minimum value of 93% and a maximum of 97%.

The ISO periodically evaluates the regulation requirements necessary to maintain CPS 2 compliance. The regulation requirements are determined by hour and vary by time of day, day of week, and month. The ISO has been able to reduce the requirements because unit performance has remained high. The average annual regulation requirement has been steadily decreasing from 181 MW for 2002 to 64 MW for 2010. The large drop between 2008 and 2009 is the result of software and operational enhancements made to the Regulation Market in 2008.

The pool of resources available for regulation hourly is a subset of all active regulation-capable generators and depends on scheduled outages and other real-time conditions. On average, about 3.9%, or 64 MW, of all available regulation capability is required to provide regulation in real time. Regulation capability is affected at the unit level by ambient temperature and at the system level by outage schedules. During 2010, monthly average regulation capability ranged from about 1,300 MW to about 1,900 MW, with an average quantity of about 1,650 MW. Gas-fired combustion-turbine units were the primary provider of regulation.

Payments to generators for providing regulation totaled $14.3 million in 2010, a decrease of $8.8 million from the 2009 costs of $23.1 million. The cost decrease was caused by a reduction in the regulation requirement, which reduced the amount of regulation purchased.

[151] More information on NERC's *Control Performance Standard 2* is available at Standard BAL-001-0.1a, *Real Power Balancing Control Performance* (May 13, 2009), http://www.nerc.com/files/BAL-001-0_1a.pdf.

Section 7
Reliability and Operations Assessment

This section discusses actions taken by the ISO to ensure real-time reliability. It includes a review of Net Commitment-Period Compensation (NCPC), “make whole” payments made to resource owners that do not recover their full as-bid cost from the energy markets.[152] The section also includes an analysis of the impact of supplemental commitments on capacity surplus in real time and an analysis of load-forecast bias. Also included are discussions of the OP 4 actions on June 24, 2010, and of the ISO and generator response and the accuracy of pricing on September 2, 2010, when a large unit was forced off line.

7.1 Daily Reliability Payments for 2010

As reported in the *2009 Annual Markets Report*, transmission improvements completed in June 2009 significantly reduced the need for out-of-market commitments of local second-contingency protection resources (LSPCRs) in SEMA and reduced second-contingency payments for the remainder of the year. As expected, LSCPR payments remained low in 2010. However, NCPC payments associated with first-contingency commitments (i.e., commitments the ISO makes in real time to ensure that forecast load and reserve requirements are met) increased sharply. Figure 7-1 and Table 7-1 summarize the NCPC payments to generators for LSCPRs, distribution, and voltage and economic (first-contingency) NCPC.

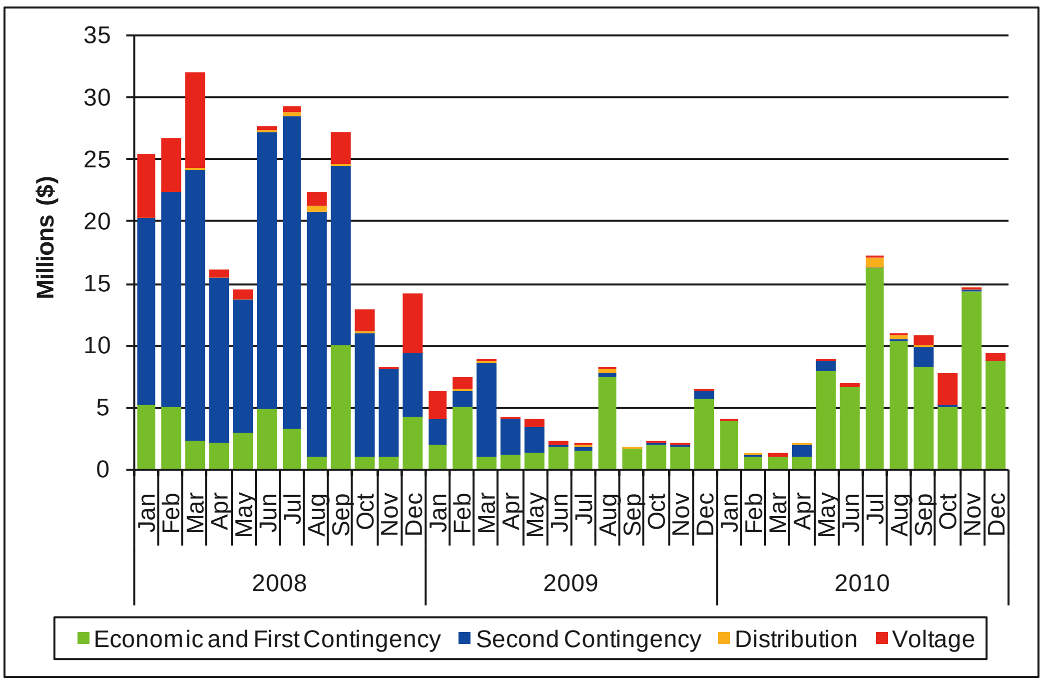

Figure 7-1: Daily reliability payments by month, January 2008 to December 2010.

[152] See Section 2.5.1 for additional discussion of the role and calculation of NCPC.

Table 7-1
Total Daily Reliability Payments, 2009 and 2010 ($)

Payment Type	2009	2010	Difference	% Change
Economic and first-contingency payments	32,556,784	84,683,101	52,126,317	160%
Second-contingency reliability payments	17,527,919	3,942,538	−13,585,381	−78%
Distribution	586,034	1,635,375	1,049,341	179%
Voltage	5,006,698	5,200,483	193,785	4%
Total	55,677,435	95,461,497	39,784,063	71%

The increase in first-contingency NCPC payments during 2010 was caused by separate, yet sometimes concurrent, operational conditions. The forced outage of generating capacity between the day-ahead and real-time markets, low day-ahead market clearing, fuel availability, and price movements all contributed to these increased payments at various times and in various situations throughout the year. One factor that contributed significantly to the level of NCPC during the year was the need to commit relatively high-cost, oil-fired generators to ensure sufficient generating capacity for the forecasted load and reserve requirements over the peak hour. Because of their high costs and inflexible intertemporal operating parameters (notification times, start times, response rates, and minimum run time), these resources generally do not clear in the day-ahead market. When committed as part of the resource adequacy assessments leading into the operating day, these resources generally operate at levels near their economic minimum during most hours of the day. They are only dispatched above these minimum operating levels for the peak hours of the day. Consequently, the total cost of running these units exceeded their total revenues collected through the energy market—the difference being paid as first-contingency NCPC. Economic (first-contingency) NCPC was 0.99% of the total generator compensation in 2010.

The need to commit generators out of market to maintain system reliability and to compensate them with NCPC has been a long-standing issue in New England. The energy produced by resources operating out of market lowers the electric energy price and thereby prevents it from accurately representing the cost of serving load. The IMM has reviewed the ISO commitments that have caused much of the economic NCPC and has found that the resources were generally needed to meet reliability needs. This can be seen in Figure 7-2, which shows that very few megawatts committed by the ISO were operating at economic minimum during the peak hour of the day for which they were committed. In general, less than 100 MW were operating at economic minimum on a system that had an average peak-hour load of 17,765 MW in 2010. A large number of megawatts operating at economic minimum would suggest that the ISO has scheduled more resources than necessary to meet load plus reserves.

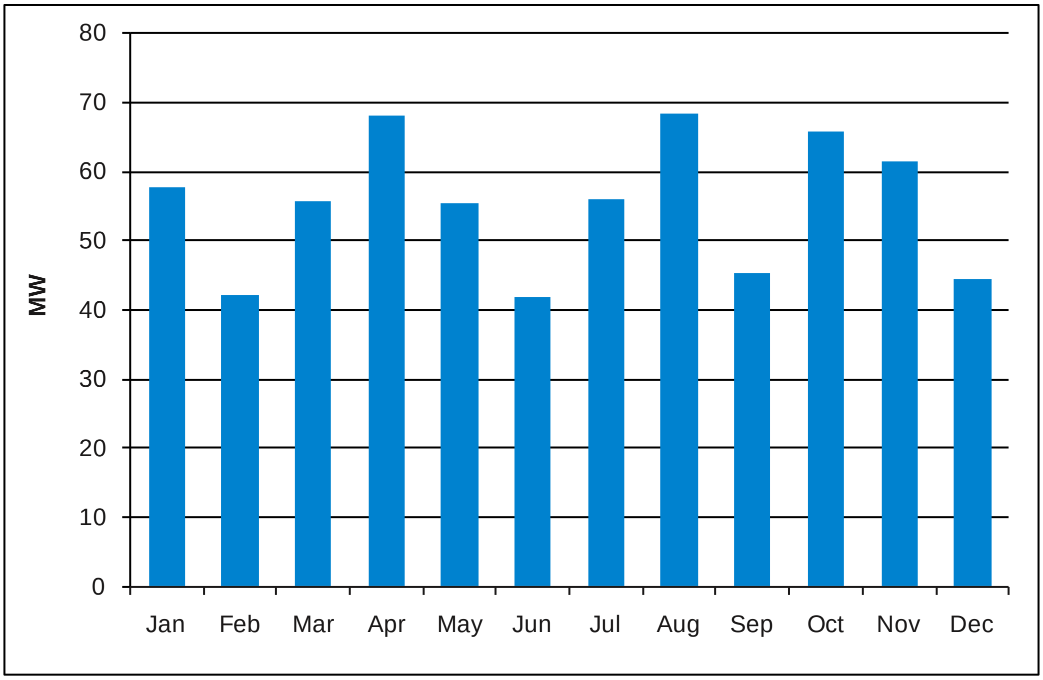

Figure 7-2: Average generation scheduled after day-ahead market closes and operated at economic minimum during the peak hour, 2010 (MW-month).

Economic NCPC is likely to remain high as long as high-cost, inflexible resources are used to meet system operating capacity needs. If these resources were replaced by more flexible resources, economic NCPC would likely decrease. Currently, the region has approximately 6,000 MW of oil or oil/gas steam units.[153] These former baseload or intermediate-load units operate very few hours per year in the energy market and receive most of their revenues from the capacity market. The floor price in the capacity market may be contributing to these resources' remaining in operation even though they are not earning profit in the energy market.

7.2 Supplemental Commitments

The IMM reviewed the commitment decisions made by the ISO during the 10:00 p.m. Reserve Adequacy Analysis process over the last three years to evaluate whether the increase in first-contingency NCPC reflects a change in practice that has resulted in a greater surplus capacity during the operating day.[154] For this analysis, the IMM measured surplus relative to each day's requirement for on-line capacity, which is load plus spinning reserve (the other operating-reserve categories can be supplied from resources available in 10 or 30 minutes from an off-line state). Specifically, the surplus is defined as the total supply available (aggregate economic maximum of on-line units plus net imports) minus system needs (load plus 10-minute spinning reserves) at a given point of time.[155]

[153] These data come from the ISO's *2010 CELT Report* (May 18, 2010), http://www.iso-ne.com/trans/celt/report/index.html.

[154] As explained in Section 2.1.2, the ISO conducts the RAA and, if necessary based on the RAA results, commits generating resources each day to ensure that sufficient resources are available to meet load plus operating reserve.

[155] *Economic maximum* (ecomax) is the highest unrestricted level of electric energy (in megawatts) a generating resource is able to produce, representing the highest megawatt output available from the resource for economic dispatch.

Surplus can arise from generation that clears in the Day-Ahead Energy Market, self-schedules, or the supplemental commitment performed in the RAA. Thus, the surplus is created both by the market as well as commitments the ISO makes for reliability. The IMM's main findings are as follows:

- The increase in NCPC does not reflect a change in ISO commitment practice.
- The average hourly surplus has decreased over time to an average of 886 MW for all hours and 259 MW for on-peak hours in 2010. This is a drop of 11% (for all hours) and 31% (during the peak hour) compared with 2009.
- The surplus varies by season. It is higher in the peak summer and winter seasons and lower in the spring and fall shoulder seasons.
- Intrahour load variation (i.e., when an instantaneous peak during the hour is higher than the integrated peak) generates apparent surplus when surplus is measured relative to the integrated hourly load.
- Participant activity, especially self-scheduled generation in the energy markets, creates most of the all-hours surplus.
- ISO commitments create most of the apparent surplus during on-peak hours.

Table 7-2 shows the average hourly surplus for the last three years. Surplus has decreased 37%, or 522 MW, since 2008. Table 7-3 presents the average hourly surplus for the daily peak. The table shows that the surplus for the peak hour has declined substantially in 2010 compared with previous years. In 2010, the average surplus for the peak hour was 259 MW, or 31% lower than in 2009 and 61% lower than in 2008.

Table 7-2
Average Hourly Surplus, All Hours, 2008 to 2010 (MW)

Year	Jan	Feb	March	April	May	June	July	Aug	Sep	Oct	Nov	Dec	Annual Average
2008	1,455	1,379	1286	1,194	1,296	1,400	1,900	1,510	1,,640	1358	1,162	1,303	1,408
2009	1,495	1,,212	1,052	1,066	672	798	973	1,267	934	943	802	773	996
2010	895	897	813	740	468	1,027	1,403	1,176	951	868	641	746	886

Table 7-3
Average Hourly Surplus, Peak Hours, 2008 to 2010 (MW)

Year	Jan	Feb	March	April	May	June	July	Aug	Sep	Oct	Nov	Dec	Annual Average
2008	754	429	494	555	776	676	704	863	908	670	421	668	661
2009	647	426	507	486	324	425	310	460	316	151	235	226	374
2010	158	131	199	230	119	270	461	360	322	305	336	199	259

Surplus is not constant within the day for expected needs at the peak hour. Surplus typically is at its minimum at the expected peak hour and greater in hours before and after the peak hour. The shape of the intraday surplus changes with the season, as the daily load shape and peak hour change with each season.

Figure 7-3 shows the average hourly surplus by hour for summer days. Surplus is at its minimum in the early afternoon and stays low until approximately HE 7:00 p.m. Surplus is at its maximum during the early hours of the morning when load is at its minimum and generators, some of them running from the previous day, cannot be shut down because of minimum-run-time constraints. The surplus curve indicates that surplus, on average, was higher in summer 2010 than in summer 2009.[156]

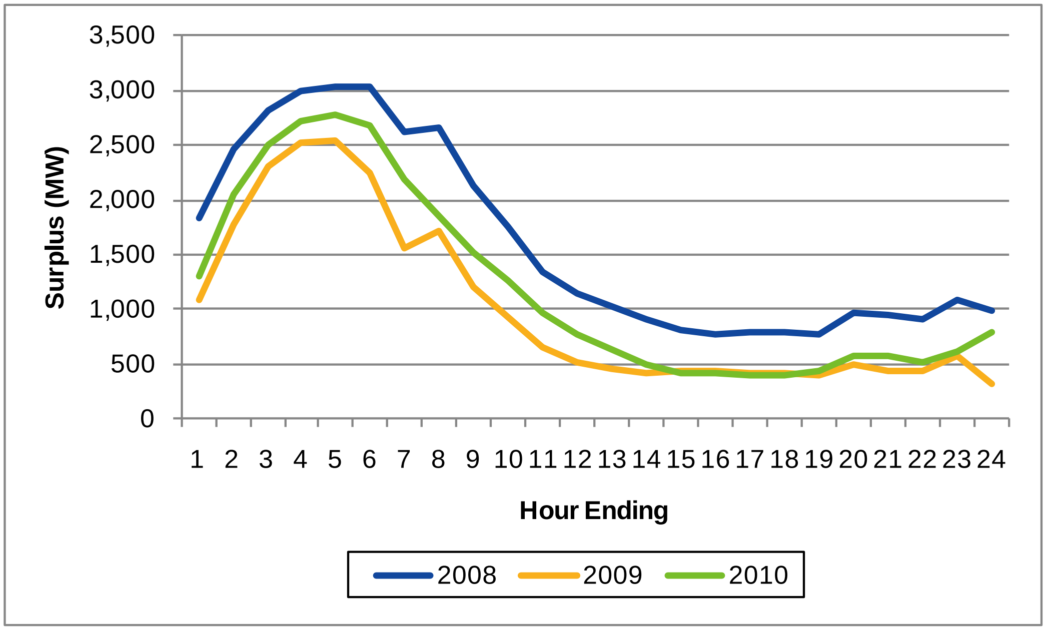

Figure 7-3: Average hourly surplus for a summer day, 2008 to 2010.

Similarly, Figure 7-4 shows the average hourly surplus for a typical winter day. Surplus is at its minimum at around HE 6:00 p.m. when the winter peak is expected. Surplus typically is at its lowest for a fewer number of hours than in the summer. Surplus is at its highest level during the early hours of the day and during the hours before the winter peak, as new units are committed in preparation to meet the expected peak of the day. The average hourly surplus was lower in 2010 than in other years.

[156] The economic recession and unseasonably cool summer weather may explain the lower level of surplus reached in the summer of 2009.

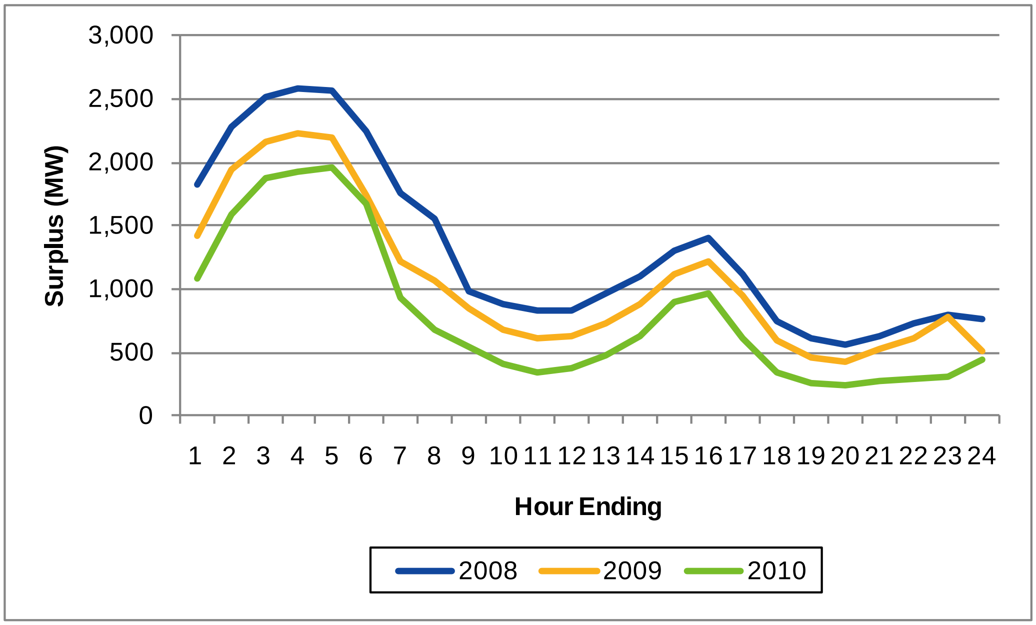

Figure 7-4: Average hourly surplus for a winter day, 2008 to 2010.

Overall, Figure 7-3 and Figure 7-4 show that the variability of load and the generator minimum-run-time constraints are the primary causes of surplus and that surplus is highest during the early morning hours. During off-peak hours, the surplus is greater because many of the generators used to meet the peak load have long start-up and minimum run times and must be turned on several hours before the peak load to be available to meet the peak. The winter pattern illustrates the same type of generator inflexibility and load variation; surplus increases during the middle of the day because inflexible generation must be committed to meet the evening peak. If load were constant during the day or generation more flexible, the surplus would be smaller. The IMM would expect the surplus to be approximately what is observed during the peak hour of the day.

Two factors cause surplus during the peak hour. First, the ISO must plan for the instantaneous peak, which is higher than the hourly integrated peak load, and second, units must be committed as whole units, not fractions of a unit. Since resources are committed to meet the instantaneous peak, rather than the integrated peak load, measuring surplus against the integrated peak, which is lower, creates a positive surplus. The IMM calculated the median of the standard deviation of hourly peak-hour loads to estimate the amount of surplus caused by the difference between the instantaneous peak load and the hourly integrated load. The value was 129 MW in 2008, 122 MW in 2009, and 132 MW in 2010. The average surplus on peak hours, calculated using integrated load, was 258 MW in 2010, and the commitment for an instantaneous peak accounts for 128 MW, which is half of the surplus on peak for that year. Additionally, because the ISO cannot commit just a fraction of a unit, if the RAA shows a need for 90 MW, for example, and the most economic resource available is a 250 MW resource, the surplus—all else equal—will be 160 MW. This analysis indicates that the ISO is not committing more capacity than needed to meet reliability requirements over the peak.

7.3 Analysis of the Load Forecast

In response to some large observed differences between the load forecast used to make supplemental commitments and actual loads, the IMM analyzed the accuracy of the ISO load forecast and whether the results were biased high or low. The IMM examined the peak load forecast made at 10:00 p.m. the night before the operating day. The analysis examined peak-load forecast error to determine whether the forecast error is biased. A significant bias (i.e., the tendency to under- or overforecast) would suggest that the forecast could be improved by adding underlying variables that explain the bias. The IMM has found the following:

- The 10:00 p.m. peak load forecast has little bias.
- The observed forecast error can be primarily attributed to weather forecast error. Load forecast error is reduced when the ISO updates weather information during the market day.
- Load forecast errors resulting from poor weather forecasts are unlikely to cause significant price changes. Simulation of the market showed the following:
    - The ISO's process of updating load forecasts and appropriately adjusting the operating plan during the market day (and in particular on the morning of the market day) reduces the potential impact of any error in the 10:00 p.m. forecast on real-time LMP.
    - Significant LMP spikes are more likely a result of sudden, large, and unexpected changes in the supply-demand balance, such as system contingencies.

The IMM analyzed the mean algebraic percent error (MALPE) to detect bias in the forecast. In addition, decomposition of mean- squared error (MSE) and econometric analysis were applied to determine whether the error term contains information that could have been identified by a better forecast. A theoretically perfect forecast would have only random errors (i.e., errors that could not be explained). The MSE decomposition splits the error into random and nonrandom components. The econometric analysis regressed the forecast error on terms that might explain the error, classifying errors into explainable and unexplainable components. The results for the three approaches are as follows:

- ***Mean Algebraic Percent Error*:** Only slight bias was detected by the measurement of errors. The average daily peak-load hour MALPE over the 18-month period studied was −0.17%, indicating a slight underforecast for that period. On a monthly basis, this rarely exceeded ±0.5%. The −0.17% average would represent 34 MW on a 20,000 MW load.
- ***Mean Squared Error Decomposition*:** The amount of potentially nonrandom error, representing the potential for forecast improvement, is low and has fallen recently. The MSE shows 90% of MSE is a result of random factors and only 10% of the MSE could be reduced by either better modeling inputs.
- ***Econometric Analysis of Error Term*:** Regression analysis shows that weather is highly correlated to forecast error. A more accurate weather forecast will reduce the forecast error and bias.

Overall, the analysis supports the findings that the bias is small and most of the error can be explained by imperfect weather forecasts. The regression analysis suggests that more accurate weather forecasts, if available, would improve the load forecast further.

7.4 System and Market Performance on June 24, 2010

The IMM analyzed market conditions and performance during the hours when the actions of an OP 4 event were invoked on June 24. The main observations and conclusions are as follows:

- Overall, the markets performed well and participants acted competitively.
- Temperatures higher than forecasted caused loads to be higher than expected.[157] Approximately 1,800 MW of generator trips and reductions across the day resulted in capacity shortages.
- The ISO invoked OP 4, *Action during a Capacity Deficiency*.
- The 30-minute operating reserve (TMOR) constraint bound for four hours.
- The 10-minute nonspinning reserve (TMNSR) constraint was violated for one five-minute dispatch interval.
- The manual market interventions by the operators were limited to actions required to manage constraints but were not included in the dispatch algorithm.
- The ISO dispatched 669 MW of demand-response resources, and 653 MW responded.
- The majority of the dispatched demand-response resources either underperformed (reduced less than their CSO) or overperformed (reduced more than their CSO). This is described in more detail in Section 3.6.

7.4.1 Operational Overview

Table 7-4 lists the implementation time of each OP 4 action on June 24. In addition to the OP 4 actions taken by the control room operators, external contracts that did not clear in the day-ahead market were cut from 12:00 (noon) until 5:00 p.m., and Master/Local Control Center Procedure No. 2 (M/LCC2), *Abnormal Conditions Alert*, was declared between 12:45 p.m. and 7:00 p.m.[158]

Table 7-4
OP 4 Actions, June 24, 2010

OP 4 Action	Action Description	Begin Time	End Time
1	Power caution; deplete 30-minute reserves	1:45 p.m.	5:15 p.m.
2	Dispatch real-time demand resources	1:45 p.m.	5:15 p.m.
3	Voluntary curtail load	2:30 p.m.	4:30 p.m.
4	Power watch	2:30 p.m.	3:15 p.m.
5	Request emergency energy	2:30 p.m.	4:30 p.m.

[157] Temperatures hit 94° F in Boston, 8°F above forecast.

[158] Master/Local Control Center Procedure No. 2 (M/LCC2), *Abnormal Conditions Alert* (December 16, 2010), http://www.iso-ne.com/rules_proceds/operating/mast_satllte/mlcc2.pdf.

Action 1 (power caution; deplete 30-minute reserves) and Action 2 (dispatch real-time demand resources) were invoked at 1:45 p.m. Between 2:27 p.m. and 3:24 p.m., five peaking units failed to start when called on line to provide energy. At 2:30 p.m., operators initiated OP 4 Action 3 (voluntary curtail load), Action 4 (power watch), and Action 5 (request emergency energy) because the capacity margin was around zero and the reserve surplus was negative.

Figure 7-5 is a timeline of the dispatch of the real-time demand response and system load on June 24, 2010. Between 2:00 p.m. and 3:00 p.m., system load fell from approximately 23,400 MW to 22,600 MW. Of the 800 MW of load reduction, an estimated 653 MW is attributable to demand response. The remaining reduction in load was caused by severe weather patterns in southwestern Connecticut. Thunderstorms began to enter the region at 1:50 p.m. and were directly over the area by approximately 2:15 p.m. The storms caused a fall in temperature, which resulted in reduced load in the area. In addition to the temperature changes, lightning strikes caused power outages in the region, which further reduced system load.

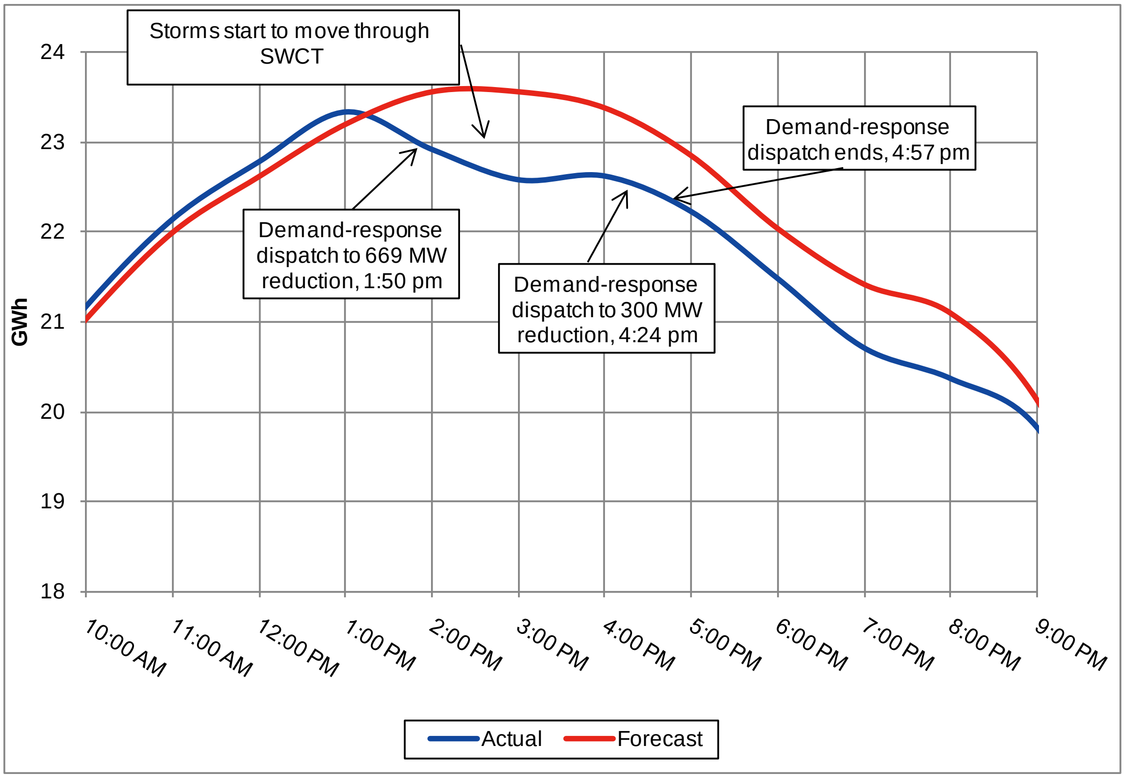

Figure 7-5: System load and demand-response event timeline, June 24, 2010.

7.4.2 Price Analysis

Real-time LMPs at the Hub were less than $50/MWh from hour-ending 1:00 a.m. through HE 8:00 a.m. During HE 12:00 (noon), reserve constraints bound, resulting in system redispatch to manage reserves and yielding a reserve market clearing price of $56.92/MWh. At approximately 12:20 p.m., additional generation tripped, exacerbating the already tight capacity conditions. At 1:45 p.m., ISO operators invoked OP 4 Action 1 (deplete 30-minute reserves) and Action 2 (dispatch real-time demand response). The TMOR constraint was violated, the reserve prices increased to $100/MWh in HE 2:00 p.m., and the hourly integrated real-time Hub LMP increased to $250.19/MWh. During HE 3:00 p.m., real-time LMPs reached their peak for the day. The hourly integrated real-time Hub LMP for HE 3:00 p.m. was $270.74/MWh, due in part to a reserve price of $129.17/MWh for the hour. In one five-minute interval, the real-time LMPs were $1,174.50/MWh, due in part to a reserve price of $950/MWh realized when the TMOR and TMNSR constraints were violated. Figure 7-6 shows real-time hourly LMPs and reserve prices for June 24, 2010.

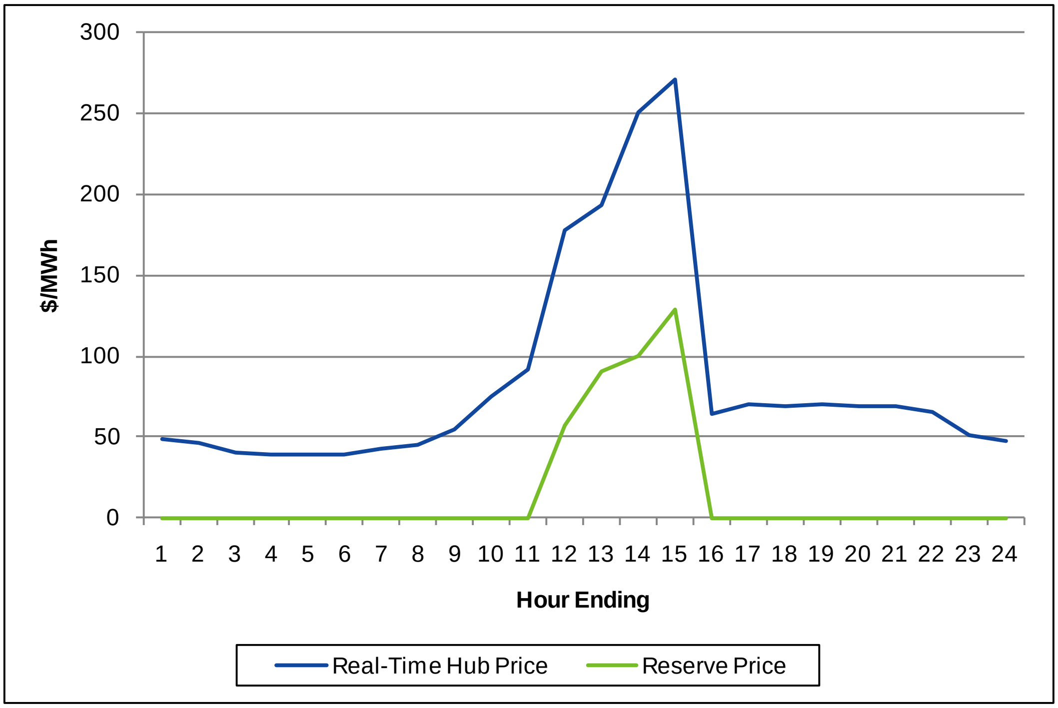

Figure 7-6: Real-time hourly Hub and reserve prices, June 24, 2010.

Through the combined effects of demand-response reductions and load drops resulting from the thunderstorms in southwestern Connecticut, load dropped substantially, and by 2:40 p.m., constraints on all reserve products ceased to bind and capacity was sufficient to meet all requirements. For HE 4:00 p.m., the hourly integrated real-time LMP at the Hub was $64.51/MWh. The hourly integrated LMPs at the Hub remained under $70/MWh for the remainder of the day.

7.4.3 Generator Bidding Behavior

On June 24, one participant was identified as the pivotal supplier needed to meet load. The participant's offer behavior on June 24 was consistent with its behavior on days when it was not pivotal. Overall, the IMM did not observe significant offer changes for participants on June 24 compared with other days in June.

7.4.4 Demand-Resource Performance

An analysis of demand-response performance on June 24, 2010, is provided in Section 3.6.3.

7.5 System and Market Performance on September 2, 2010

On September 2, 2010, at 1:09 p.m., a large resource tripped. Many generators were called on or had their desired dispatch point (DDP) increased to restore system frequency, return transmission interfaces back to within limits, and restore area control error (ACE) and operating reserves in accordance with established criteria (see Section 2.4). The ISO was unable to return the ACE to its predisturbance value within 15 minutes, as required by the NERC standard, taking 23 minutes to accomplish this task.

According to a review by ISO System Operations, inadequate generator response to ISO electronic dispatch instructions was an important contributing factor to the inability of the ISO to restore ACE within the 15-minute time requirement. The IMM analyzed market pricing, generator performance, and the performance of the dispatch software to better understand why the ISO took longer than 15 minutes to return the ACE to predisturbance levels. As a result of this review, the IMM recommends reviewing the rules that define the instructions for following dispatch and how real-time prices are set, especially in periods of shortages of reserves. The reasons for these recommendations are detailed below.

7.5.1 Generator Compliance with Dispatch Instructions

The analysis provides no conclusive evidence to suggest that generators willfully ignored dispatch instructions. While the aggregate failure of the generation fleet to achieve DDP resulted in a failure to regain ACE within 15 minutes, the performance of generators during the event was not the result of market manipulation.

The review examined generator response to the contingency-dispatch instructions issued by the ISO approximately two minutes after the trip of the resource. This set of dispatch instructions was intended to return the system ACE to predisturbance levels. This review found the following:

- No evidence that any generator withheld capacity during this time period.
- Generator response to the dispatch instructions was mixed. One-hundred forty-seven generators were dispatched for a total of 1,942 MW. The total generator response within 14 minutes of the disturbance was 1,209 MW (62%), 729 MW short of what was electronically or verbally dispatched, as follows:
    - Fifty-six generators were off line and given a dispatch order to start. A total of 936 MW of off-line resources was dispatched, and the total response was 673 MW (72%)—263 MW short of what was dispatched. The performance of off-line resources is consistent with past off-line unit performance.
    - Ninety-one generators were on line and given a dispatch order to ramp up. A total of 1,006 MW was dispatched, and the total response was 536 MW (53%)—470 MW short of what was dispatched. The response of on-line resources was poorer than expected.
- Because of the high loads at the time, many of the units providing operating reserve were operating at the top of their range, with each unit providing only a small amount of operating reserve. Because of the high heat and humidity and the difficulty of moving a unit at the top of its operating range, on-line generators did not perform consistent with their offer data parameters, in particular, ramp rates and economic maximum.[159] Generator ramp rate and ecomax parameters submitted for the day apparently did not reflect the precise capabilities of the units, given that day's temperature and humidity. ISO system operators would have

[159] *Ramp rate* is the rate at which a generating resource can increase its output, usually expressed in MW/minute.

possessed better information to dispatch the system had such parameters been more accurately reported to the ISO.

- The outage of the large flexible generator mentioned earlier made it more difficult to return the ACE to predisturbance levels.

Table 7-5 provides a snapshot of aggregate system performance for all generators issued dispatch instructions. The time intervals detailed below are inclusive of every available interval between 1:06 p.m. (three minutes before the trip) and 1:32 p.m. (the time ACE was recovered) with the exceptions of 1:12 p.m., 1:16 p.m., and 13:26 p.m. because no new scheduling, pricing, and dispatch (SPD) cases were run and approved in those intervals. The time interval (−3), which reflects system conditions three minutes before the trip, includes the large resource that tripped; all other intervals exclude the units.

Table 7-5
Aggregate System Performance, September 2, 2010

Units	# of Units / ± DDP (MW)[(a)]	−3 (1:06 p.m.)	0 (1:09 p.m.)	+2 (1:11 p.m.)[(b)]	+12 (1:21 p.m.)	+14 (1:23 p.m.)	+23 (1:32 p.m.)
Units below 90% DDP	# of units	18	32	95	79	50	33
	±DDP	−101.5	−539.7	−1,642.6	−949.3	−927.5	−1,355.1
Units between 90% and 100% DDP	# of units	90	96	102	144	103	107
	± DDP	−169.8	−186.5	−307.4	−336.8	−227.5	−191.4
Units above 100% DDP	# of units	69	52	32	57	85	98
	±DDP	114.5	92	22.3	112.4	546.4	497
All Units	# of units	177	180	229	229	238	238
	±DDP	−156.8	−634.2	−1927.7	−1,173.7	−608.6	−1,049.5

(a) ±DDP = (Current Dispatch Instructions – Current Output of Units given DDP).

(b) The +2 time interval is the contingency SPD case.

Figure 7-7 illustrates the aggregate performance (generator output) of all units given DDPs relative to the systemwide dispatch instructions and the real-time bid in economic maximum. All generators were not sent to their ecomax because many of them were constrained by their ramp rate. Most of the megawatts that could not be realized because of ramp-rate constraints were from a few large oil-fired units.

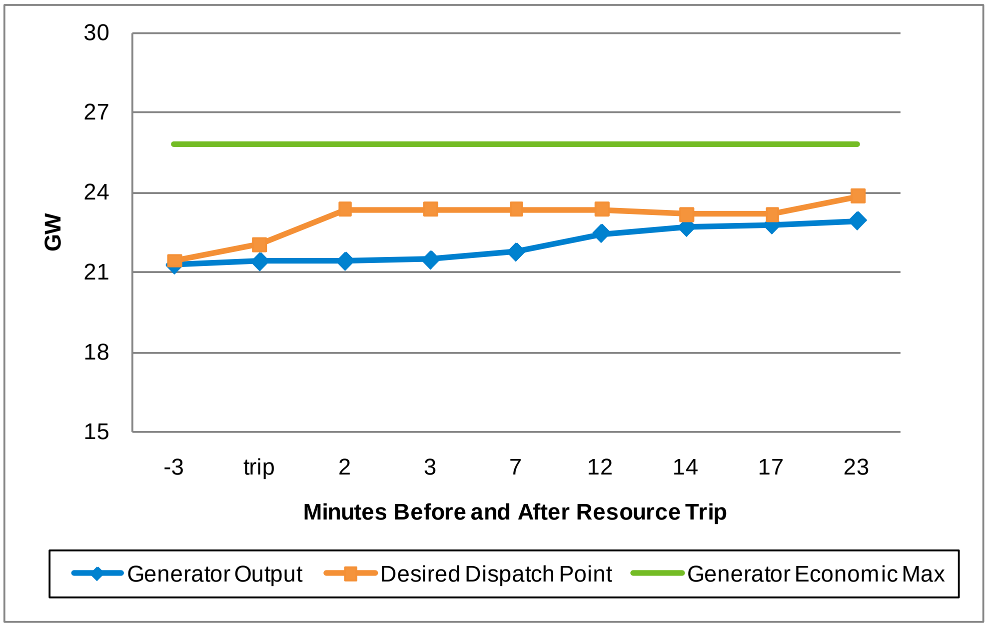

Figure 7-7: Total system generator output relative to total system desired dispatch and total economic maximum, September 2, 2010.

7.5.2 Energy and Reserve Prices

Following the resource trip, the ISO was short of 10-minute reserves, relative to the market requirement, for almost 40 minutes. However, 10-minute reserve prices reached the $850/MWh for only 20 minutes (four pricing intervals).[160] During the remaining 20 minutes of the physical shortage, 10-minute reserve prices averaged $185/MWh rather than the $850/MWh TMNSR Reserve Constraint Penalty Factor. The LMP calculator (see below) produced energy and reserve prices that did not appropriately reflect the shortage of TMNSR.

7.5.3 Background

The LMP calculator is an automated optimization program that runs every five minutes and generates the ex-post prices used in settlements based on the most recent telemetry and unit-dispatch and scheduling (UDS) solutions.[161] One important purpose of ex-post pricing and the LMP is to prevent resource owners from increasing prices by withholding capacity in real time and forcing the dispatch algorithm to select a more expensive unit and have that unit set the LMP. However, as described below, the IMM's review of pricing during September 2 has shown that when resources operate at less than the issued DDP, the LMP calculator may produce LMPs and reserve prices that do not properly reflect scarcity conditions.

[160] The dispatch and pricing algorithm includes several operating-reserve constraints to ensure that the dispatch maintains sufficient operating reserves whenever possible. A constraint is violated in a dispatch if fewer reserves are on the system than needed to meet the requirement. When this occurs, the value of the constraint should be added to the energy price. The constraint for having insufficient reserves to meet the TMNSR requirement is $850/MWh. Therefore, the energy price for a system that has insufficient TMNSR should be $850/MWh plus the cost of the marginal generating unit.

[161] A second-case identification, called contingency UDS or CD UDS will provide new DDP levels. The distinction is not important for the explanation.

7.5.4 Prices on September 2, 2010

Figure 7-8 plots the Hub LMP, the total system 10-minute reserve available and required, and the 10-minute spinning reserve market clearing price for the hour on September 2, 2010, during which the large generator tripped and the ACE was not returned to precontingency levels within 15 minutes. The initial movement of prices is consistent with supply-demand conditions. As the quantity of reserve on the system decreased, the TMNSR clearing price and Hub LMP both rose. A shortage of TMNSR caused a TMNSR constraint violation in the UDS and an $850/MWh TMNSR clearing price from 1:50 p.m.to 13:35 p.m.

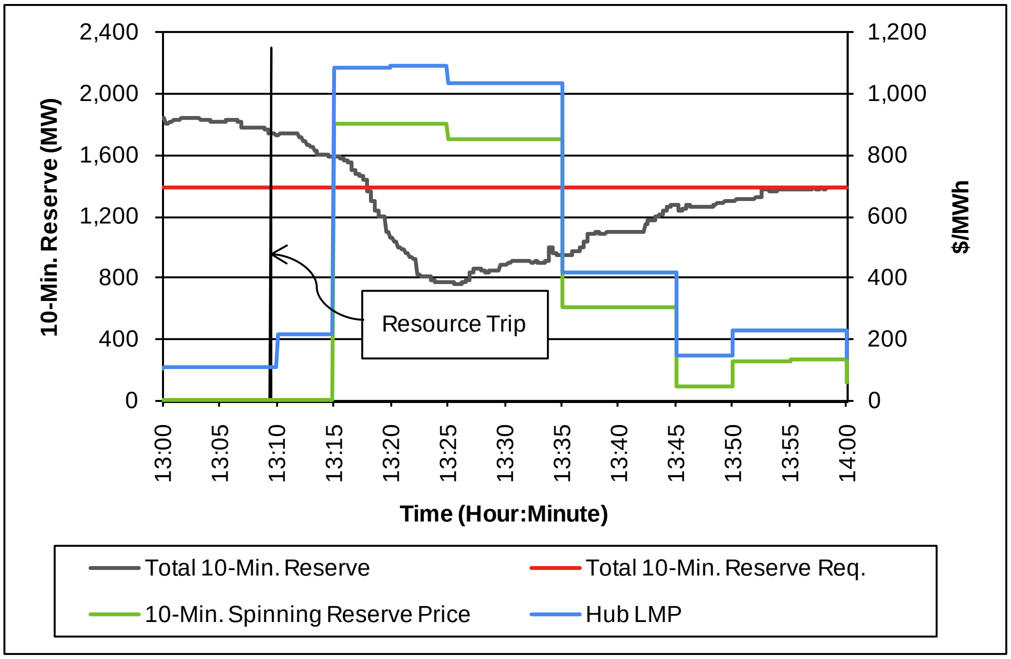

Figure 7-8: LMP calculator TMNSR clearing price, and Hub LMP overlaid with actual system reserves, September 2, 2010.

The reserve clearing price lagged the system condition at the beginning of the event because the last UDS case before the resource trip indicated sufficient reserves on the system. Once the control room approved the dispatch case reflecting the loss of the largest unit, the next LMP calculator run appropriately reflected the shortage conditions. The next UDS case sent dispatch instructions that, if generators followed, would have met system load plus operating reserves. But, as discussed earlier, generators were unable to follow these dispatch instructions and, while load was met, operating reserves were not. Figure 7-8 shows that the pricing that resulted from the combination of the UDS run and the LMP calculator for 1:35 p.m. to about 1:57 p.m. assumed that reserves on the system were sufficient. However, in actuality, reserves were not sufficient, and prices should have reflected the violation of the $850/MWh TMNSR constraint.

These results led the IMM to recommend that the ISO review the way real-time prices are set to ensure that prices reflect supply and demand of energy and reserves under all market conditions.

The September 2, 2010, event also highlighted the ambiguity of the rules regarding the failure-to-follow dispatch instructions. Two sections of *Market Rule 1* reference following dispatch instructions: Section III.1.7.20, “Information and Operating Requirements,” and Section III.3.2.3(e), “NCPC

Credits."[162] The first reference generally requires resources to follow dispatch instructions but does not include any definition for following dispatch instructions. The second reference requires resources to be within 10% of their dispatch instructions to be eligible to receive NCPC and considered for setting the LMP. The lack of a performance standard in the general requirement has resulted in considering a resource that is operating within 10% of its dispatch instruction as following its dispatch instructions for all purposes. The IMM recommends that the ISO review the failure-to-follow rules, especially whether a different definition of following dispatch instructions, for purposes other than receiving NCPC payments and setting price, is appropriate.

7.6 Internal ISO Market Operations Assessment and Administrative Price Corrections

The ISO participated in several audits during 2010. The following audits were conducted to ensure that the ISO had followed the approved market rules and procedures and to provide transparency to New England stakeholders:

- **SAS 70 Type 2 Audit—**In November 2010, the ISO successfully completed a SAS 70 Type 2 Audit, which resulted in an "unqualified opinion" about the description of the Market Operations and Settlements processes and systems and design and operating effectiveness of controls.[163] Developed by the American Institute of Certified Public Accountants, the SAS 70 Audit is used to cover aspects of service organization internal controls that may be relevant to a user organization's internal controls as it relates to a financial statement audit. Entities such as Regional Transmission Organizations complete SAS 70 Audits to assist user organizations in evaluating their internal controls over financial reporting.

  The ISO's SAS 70 Type 2 Audit is a rigorous and detailed examination of the business processes and information technology used for activities related to bidding into the market, accounting, billing, and settling the market products of energy, regulation, transmission, capacity, demand response, reserves and related market transactions. Conducted by the auditing firm KPMG LLP, the Type 2 Audit covered a 12-month period from October 1, 2009, through September 30, 2010. The SAS 70 Type 2 Audit includes the auditor's opinion on the fairness of the description of the controls contained in the audit report prepared by the ISO, suitability of the design of the controls for achieving the specified objectives, and the operating effectiveness of the controls tested.[164] The ISO conducts a SAS 70 Type 2 Audit annually. The 2010 SAS 70 Audit report is available to participants upon request through the ISO external website.

[162] *Market Rule 1*, Section III.1.7.20, "Information and Operating Requirements," and Section III.3.2.3(e), "NCPC Credits" (March 14, 2011), http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_sec_1-12.pdf.

[163] A SAS 70, *unqualified audit opinion* is issued when three conditions are met as determined by the audit firm. First, the description of the controls in the ISO audit report (see footnote below) fairly presents the relevant aspects of the service organization's controls. Second, the overall design of the controls is sufficient to meet the specified control objectives. Third, the firm has collected and evaluated sufficient competent evidence through applied tests to specific controls and determined that the controls are operating with sufficient effectiveness to provide reasonable assurance that the control objectives were achieved during the test period.

[164] KPMG. *Report on Controls Placed in Operation Pertaining to the Market Operations and Settlements Processes and Systems of ISO New England Inc. and Tests of Operating Effectiveness for the Period October 1, 2009 to September 30, 2010, Prepared Pursuant to Statement on Auditing Standards No. 70, as Amended.* This report is available to participants on request through the ISO's website, http://www.iso-ne.com/aboutiso/audit_rpts/index.html and http://www.iso-ne.com/aboutiso/audit_rpts/SAS70Request.do.

- **Review of the Forward Capacity Market Project**—The ISO internal audit department conducted a review of the Forward Capacity Market project including the market services and settlement processes. This review examined the systems development process, application test planning and results, the development of business and related control procedures, and the production migration process.

- **Market-System Software Recertification—**The ISO has committed to a practice of engaging an independent third party, PA Consulting, to review and certify that the market system software complies with *Market Rule 1*, the manuals, and standard operating procedures. This recertification takes place every two years or sooner, in the case of a major market system enhancement or new market features. After conducting detailed tests and analysis of the applicable mathematical formulations, PA Consulting issues a compliance certificate for each market system module it audits. The certificates provide assurance that the software is operating as intended and is consistent with *Market Rule 1* and associated manuals and procedures.

In 2010, PA Consulting issued the following certifications:[165]

- Regulation Clearing Price Market Software, December 21, 2010
- Simultaneous Feasibility Test Software, December 21, 2010
- Forward Capacity Auction Market Clearing Engine Software, December 21, 2010
- Locational Marginal Price Calculator Market Software, April 14, 2010
- Locational Forward Reserve Market Software, December 21, 2010

Table 7-6 shows the ISO's administrative price corrections. There are very few corrections, indicating that pricing is being done correctly the first time.

Table 7-6
Administrative Price Corrections

Location/Load Zone	Congestion Component
Data error	4
Hardware/software outage, scheduled	3
Hardware/software outage, unscheduled	2
Software limitation	21
Software error	1
Dead-bus logic	35

[165] All certificates are available to participants upon request through the ISO external website: http://www.iso-ne.com/aboutiso/audit_rpts/index.

Section 8
Data Appendix

This appendix contains details on the energy, forward capacity, locational forward reserve, and regulation markets. It also contains information about actions taken to ensure reliability and the tariff charges that fund ISO operations and provide compensation for the products and services provided by participants through the tariff.

8.1 Energy Appendix

The energy appendix has information about the energy markets covered in this report that is not essential for evaluating the competitiveness and efficiency of the markets.

8.1.1 Competitive Measures Supporting Information

Table 8-1 shows the average and minimum heat rates of generating resources in New England by generation technology type and input fuel.

Table 8-1
Average and Minimum
Heat Rates for New England Generators, 2010 (Btu/MWh)

Technology	Fuel Type	Average Heat Rate	Minimum Heat Rate
Combined cycle	Gas	7,900	6,900
	No. 6 oil (1%)	10,100	10,100
Combustion turbine	Diesel	12,300	11,400
	Gas	11,000	8,900
	Jet fuel	13,200	10,500
	No. 2 oil	16,100	15,500
Steam	Coal	9,600	8,700
	Gas	11,000	10,200
	No. 6 oil (1%)	10,400	9,000
	Other	10,300	10,000
	Wood	12,500	10,000

Table 8-2 presents yearly capacity factors by fuel type for 2008 to 2010.

Table 8-2
Yearly Capacity Factors by Fuel Type, 2008 to 2010 (%)

Fuel	2008	2009	2010 (descending sorted)	Change 2010 to 2009
Wood/propane	91.46	97.25	96.68	-0.57
Nuclear	89.29	89.67	93.98	4.31
Refuse/ wood	86.13	77.33	92.06	14.73
Coal	75.92	67.10	88.87	21.77
Wood	78.50	71.20	87.47	16.27
Refuse	86.44	85.88	83.75	-2.13
Refuse/natural gas	69.39	76.52	82.02	5.50
Wood/coal	80.35	81.09	80.57	-0.52
Wind	47.19	28.54	61.90	33.36
Wood/ natural gas	53.83	47.67	58.25	10.58
Hydro	57.34	56.67	51.99	-4.68
Natural gas	37.81	39.65	45.13	5.48
Coal/oil	61.24	37.39	34.89	-2.50
Natural gas/oil	25.23	20.69	25.09	4.41
Oil/natural gas	2.83	2.92	4.07	1.15
Oil	1.43	0.70	0.78	0.08

8.1.2 Day-Ahead Market

Table 8-3 and Table 8-4 show the amount of day-ahead supply and demand by category for 2008 to 2010.

Table 8-3
Day-Ahead Demand by Category, 2008, 2009, and 2010 (MW)

	2008	2009	2010
Fixed demand	82,760,527	83,580,944	86,328,275
Price-sensitive demand	42,600,688	37,677,821	33,366,584
Exports	7,867,334	6,608,331	9,164,496
Virtual demand	14,828,780	9,344,550	8,539,265
Total	148,057,328	137,211,646	137,398,620

Table 8-4
Day-Ahead Supply by Category, 2008, 2009, and 2010 (MW)

	2008	2009	2010
Fixed supply	80,331,548	83,327,976	83,916,460
Price-sensitive supply	35,822,261	30,417,164	36,089,684
Imports	17,381,466	15,185,951	13,464,315
Virtual supply	17,086,241	10,190,515	5,755,389
Total	150,621,516	139,121,606	139,225,849

8.1.3 Real-Time Market

This section provides additional information on real-time generation and the price difference between the Day-Ahead and Real-Time Energy Markets.

8.1.3.1 Real-Time Generation

Figure 8-1 shows the annual hydroelectric energy production from resources in New England for 2000 to 2010.

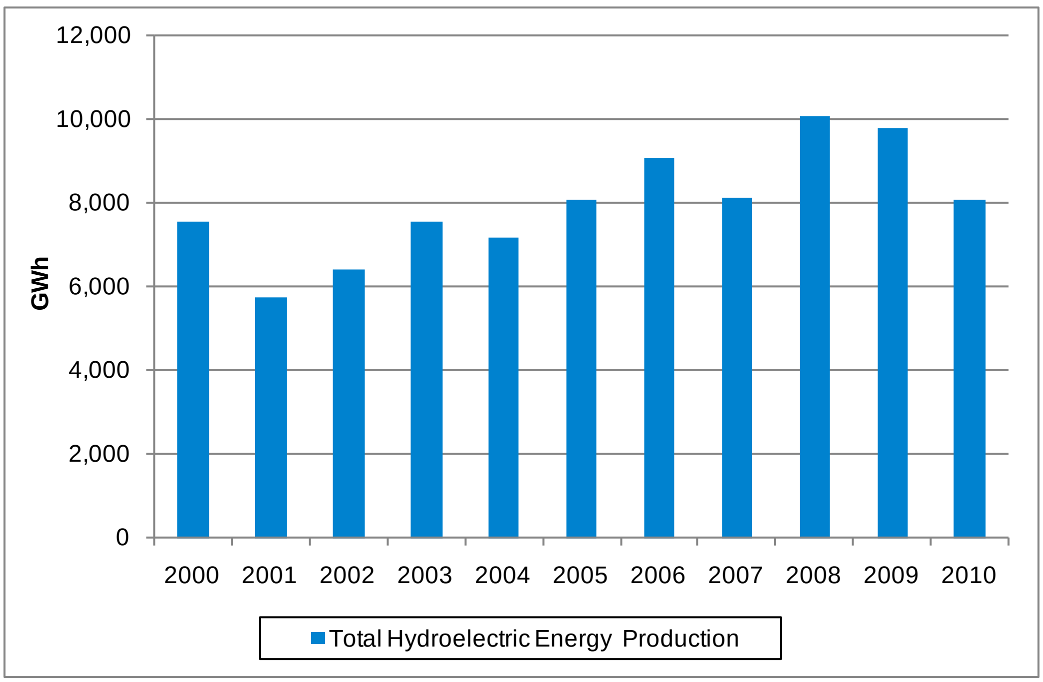

Figure 8-1: Annual hydroelectric energy production, 2000 to 2010.

Table 8-5 shows the annual generation by fuel type with comparisons to 2010.

Table 8-5
Yearly Generation by Fuel Type, 2008 to 2010 (MW)

Fuel	2008	2009	2010 (descending sorted)	Change 2010 to 2009	% Change
Gas	38,338	38,163	42,030	3,867	10%
Nuclear	35,547	36,231	38,364	2,133	6%
Oil/gas	12,721	12,487	15,541	3,054	24%
Coal	18,596	14,558	14,131	-427	−3%
Total renewables	7,539	7,331	7,686	355	5%
Hydro: run of river and pondage	8,466	8,354	7,227	−1,127	−13%
Wood/refuse	4,411	4,082	3,770	−312	−8%
Refuse	2,721	2,504	2,851	347	14%
Hydro: pumped storage	1,623	1,419	854	−565	−40%
Oil	1,918	895	570	−325	−36%
Wind	28	261	491	230	88%
Landfill gas	113	256	342	86	34%
Steam	157	155	167	12	8%
Methane/refuse	43	44	37	−7	−16%
Steam/refuse	30	28	27	−1	−4%
Solar	1	1	2	1	100%
Under 5 MW	35	-	-	-	0%
Total generation (GWh)	124,749	119,437	126,403	6,966	6%

The annual average day-ahead premium for the Hub and eight load zones is shown in Table 8-6.

Table 8-6
Average Day-Ahead Premium, 2008 to 2010 ($/MWh)

Location	2008	2009	2010
CT	$1.42	−$0.16	−$0.01
Hub	−$0.13	−$0.47	−$0.67
ME	$0.62	−$0.38	−$0.37
NEMA	−$0.55	−$0.34	−$1.02
NH	−$0.21	−$0.47	−$0.68
RI	−$0.20	−$0.44	−$0.76
SEMA	$1.11	−$0.34	−$0.95
VT	−$0.04	−$0.49	−$0.33
WCMA	−$0.15	−$0.45	−$0.55

8.1.3.2 Self-Scheduled Generation

Table 8-7 shows cleared supply from self-scheduled generation in the day-ahead market and the amount of self-scheduled generation in the real-time market for 2009 and 2010. Over time, additional self-scheduled megawatts committed outside the day-ahead market have declined. Overall, the percentage of self-scheduled generation supply in real-time that cleared as a self-schedule in day-ahead decreased from 94% in 2009 to 93% in 2010.

Table 8-7
Day-Ahead, Real-Time, and
Real-Time Supplemental Self-Schedules, 2009 to 2010 (GWh)

Year	Month	Day-Ahead Self-Schedule (GWh)	Real-Time Self-Schedule (GWh)	Real-Time Supplemental Self-Schedule (GWh)	Percentage (Day Ahead/ Real Time)
2009	Jan	7,728	8,333	605	93%
	Feb	6,895	7,305	410	94%
	Mar	7,555	8,044	489	94%
	Apr	7,144	7,563	418	94%
	May	6,294	6,755	461	93%
	Jun	6,891	7,338	448	94%
	Jul	7,383	7,806	423	95%
	Aug	8,087	8,540	454	95%
	Sep	6,886	7,247	362	95%
	Oct	5,793	6,202	409	93%
	Nov	5,865	6,329	464	93%
	Dec	6,790	7,371	580	92%
2010	Jan	7,526	8,131	605	93%
	Feb	6,670	7,110	440	94%
	Mar	7,200	7,723	523	93%
	Apr	6,306	6,768	463	93%
	May	5,854	6,356	502	92%
	Jun	7,284	7,821	537	93%
	Jul	7,942	8,410	468	94%
	Aug	7,479	8,035	556	93%
	Sep	6,786	7,208	422	94%
	Oct	7,171	7,700	529	93%
	Nov	6,312	6,865	553	92%
	Dec	7,323	8,159	836	90%

8.1.3.3 Weather

As illustrated in Figure 8-2, New England monthly temperatures in 2010 generally were consistent with long-term averages. Overall, temperatures were slightly warmer than normal.[166] Despite a sluggish economy, New England electricity consumers pushed electricity consumption to new heights over the summer. Peak demand hit record levels for the individual months of May and September, and all-time record consumption for a one-month period was set in July. Some highlights from summer 2010 are as follows:

- July 2010 was the second-hottest July in New England since 1960.
- New England's all-time electricity consumption for one month was recorded in July 2010 at 13,385 GWh. The previous one-month consumption record was set in July 2006, with 13,365 GWh of electricity used.
- Energy consumption in June, July, and August totaled 36,863 GWh, ranking summer 2010 in third place behind summer 2005 (38,150 GWh) and summer 2006 (37,076 GWh).
- May's peak demand set a new record for that month: 22,817 MW on May 26. September's peak demand set a new record for that month: 26,098 MW on September 2.

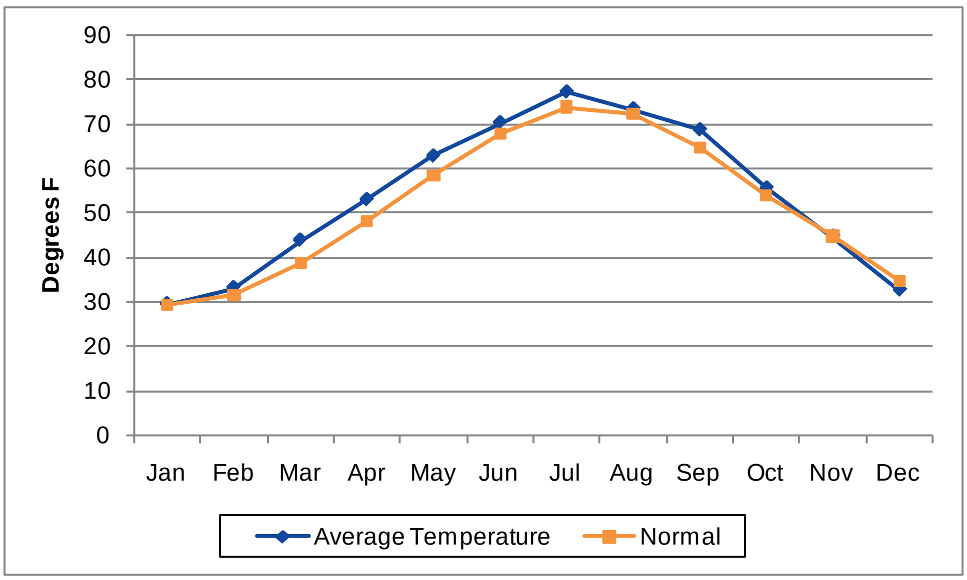

Figure 8-2: Average monthly 2010 temperatures compared with normal temperature values.

8.1.3.4 Load Factors

The load factor shows the relationship of the average hourly load to the peak load over the course of a year. Low load factors indicate the amount of capacity that must be maintained year-round to meet the high loads that may last only for a few hours during the year. Figure 8-3 shows the long-term trend of declining load factors for New England expressed as a percentage for weather-normalized

[166] Weather information is available at http://www.weather.gov/climate/index.php?wfo=box. Normalized climate values cover 1971 to 2000.

load.[167] New England is a summer-peaking region because of the use of air conditioning in hot weather. The increase in the use of air conditioning has outpaced the growth in overall energy consumption, causing load factors to decline. In addition to air-conditioning saturation, the conversion from individual room air conditioning to central air conditioning and an increase in the size of the homes being cooled have contributed to the long-run decline in the summer-peak load factor. The load factor increased in 2011 as a result of the region's coming out of an economic recession, which had a greater impact on the use of electricity overall compared with the use of air conditioning.

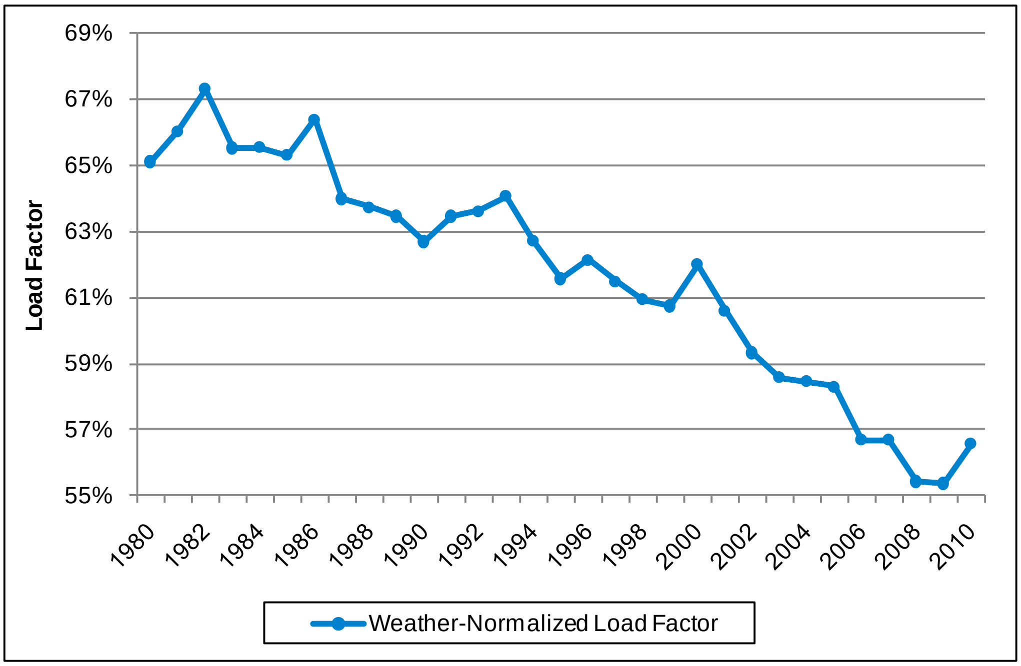

Figure 8-3: New England summer-peak load factors, weather-normalized load, 1980 to 2010.

8.1.3.5 Marginal Resource Detail

This section provides exhibits identifying trends in the frequency with which different resource classes, including external transactions, set price in the ISO.

Figure 8-4 and Figure 8-5 show the annual percentage of time that imports set price in the day-ahead and real-time markets, respectively, in on- and off-peak hours.

[167] A *weather-normalized load factor* is the ratio of the average hourly demand during a year to the peak hourly demand, both adjusted to normal weather conditions.

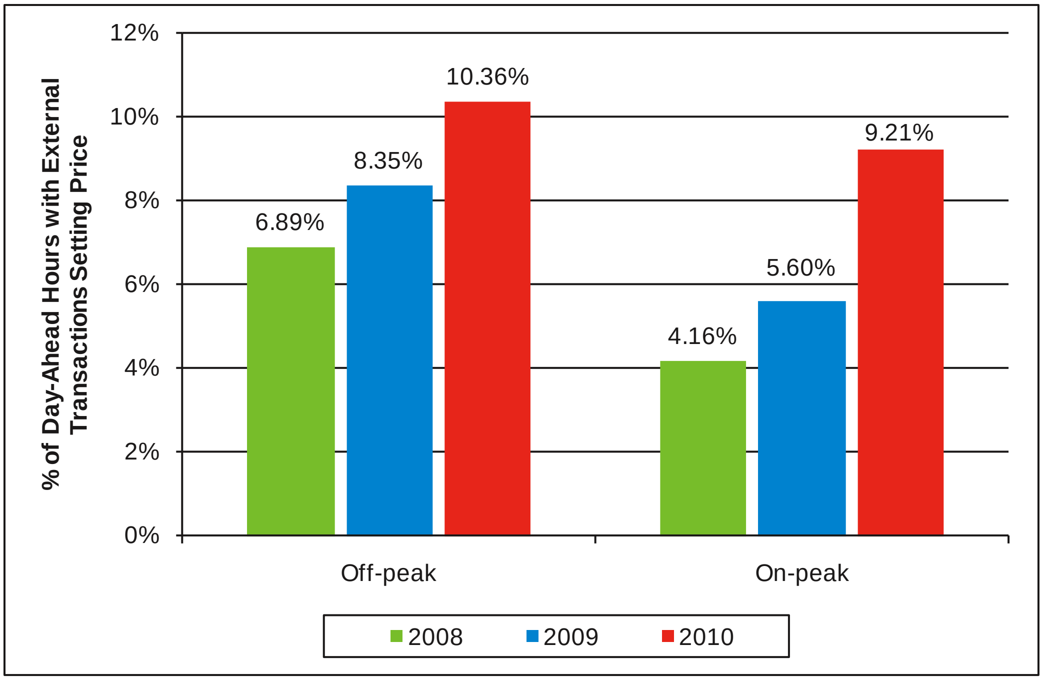

Figure 8-4: Day-ahead external-transaction price setting, on and off peak, 2008 to 2010.

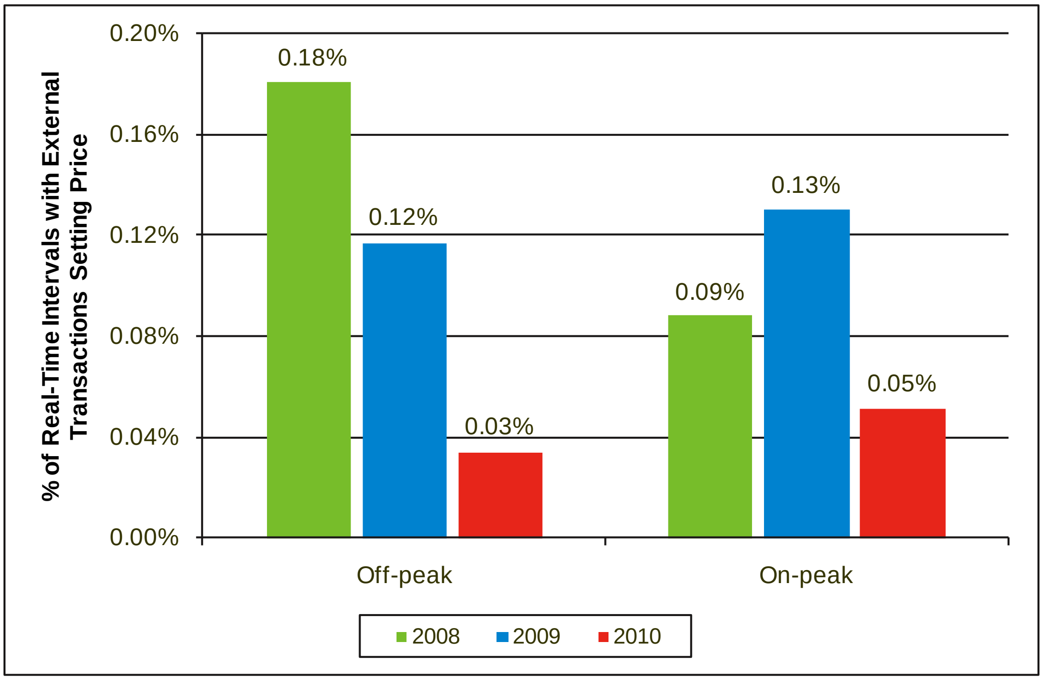

Figure 8-5: Real-time external-transaction price setting, on and off peak, 2008 to 2010.

Figure 8-6 and Figure 8-7 show the amount of time that imports were marginal within an hour as a percentage of the total amount of time that all price setters were marginal within that hour for the Day-Ahead and Real-Time Energy Markets.

Figure 8-6: External-transaction price setting by hour, day-ahead market, 2008 to 2010.

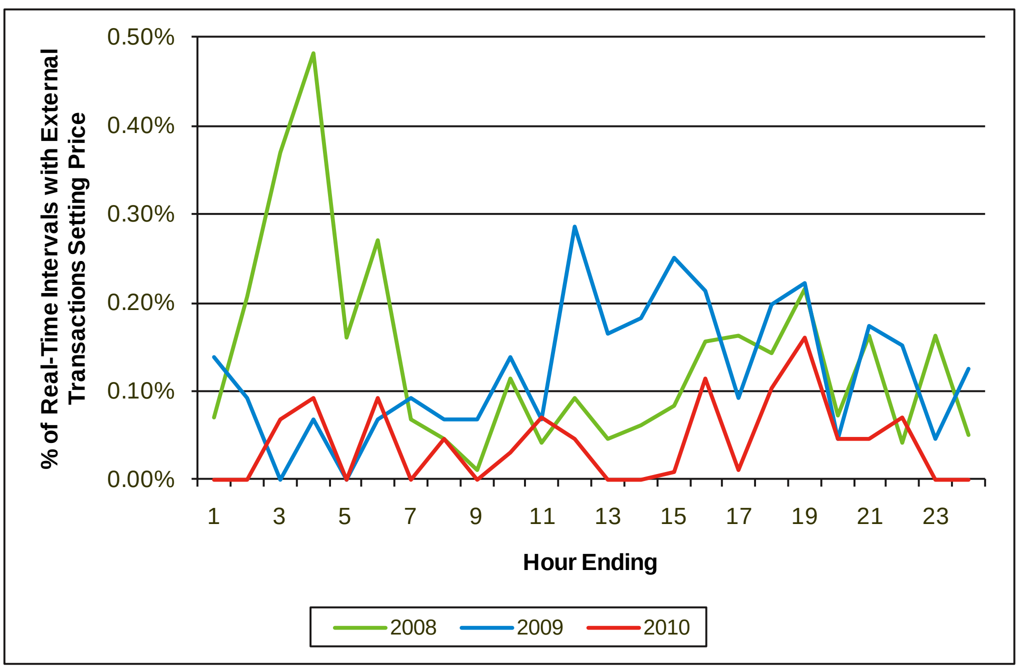

Figure 8-7: External-transaction price setting by time of day, real-time market, 2008 to 2010.

8.1.3.6 Interchange Details

This section provides information on the transfer of electric energy between balancing authorities for 2008 to 2010, as well as average hourly flow levels by interface.

Figure 8-8 shows scheduled imports, exports, and net external energy flow for 2008 through 2010.

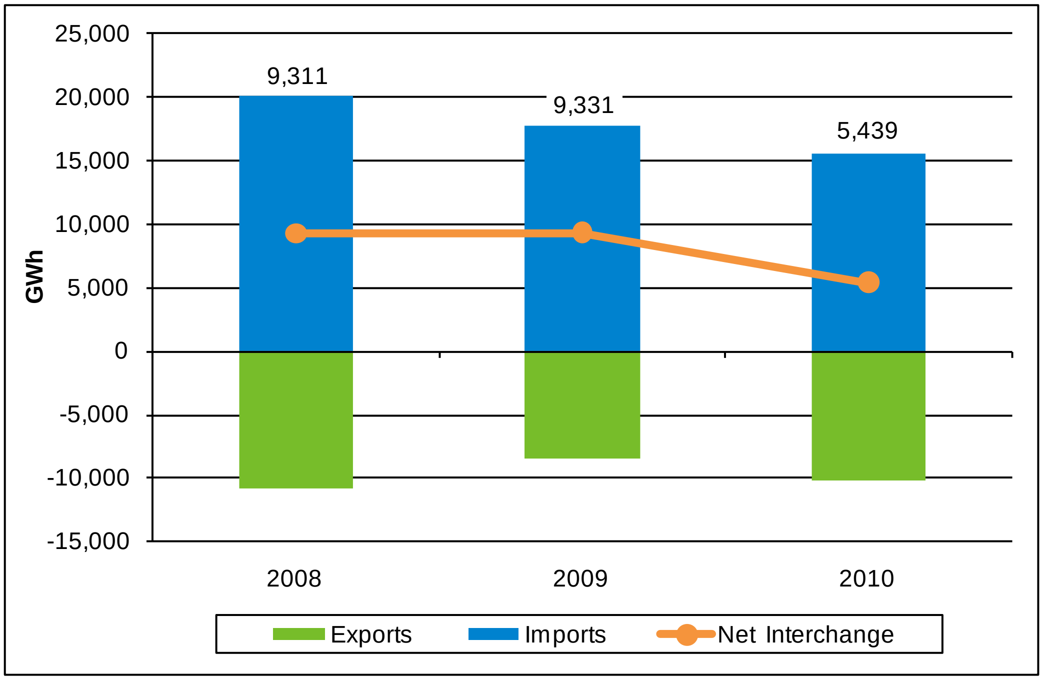

Figure 8-8: Scheduled imports and exports and net external energy flow, 2008 to 2010 (GWh).

Figure 8-9 to Figure 8-12 present average metered flow by hour over the priced external interfaces with neighboring balancing authority areas.

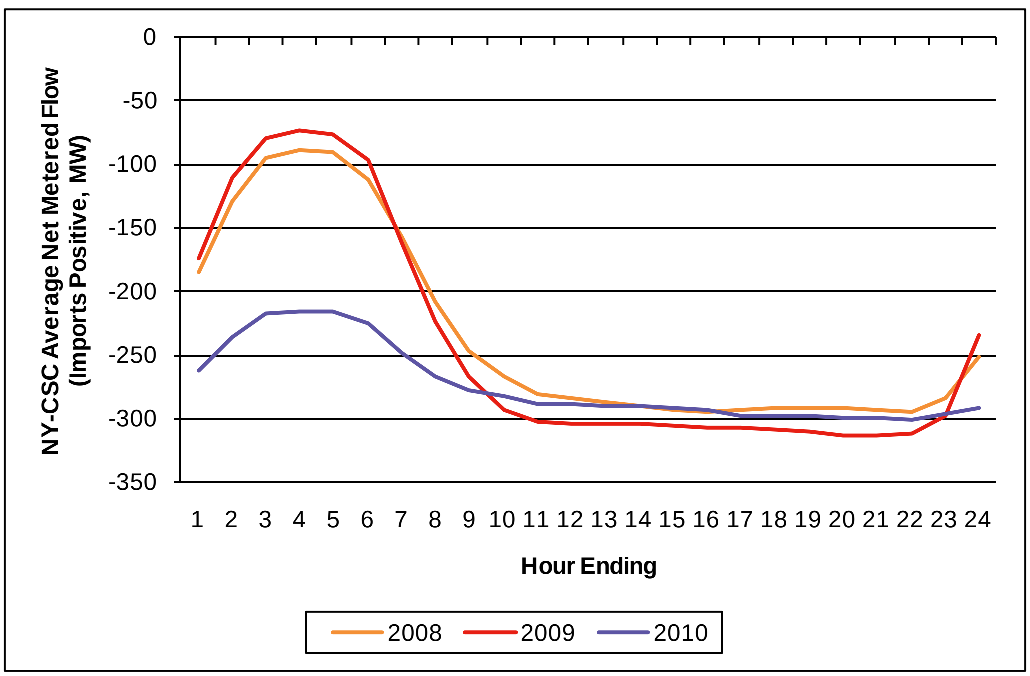

Figure 8-9: New York-Cross-Sound Cable, average net metered flow by hour of the day, 2008 to 2010.

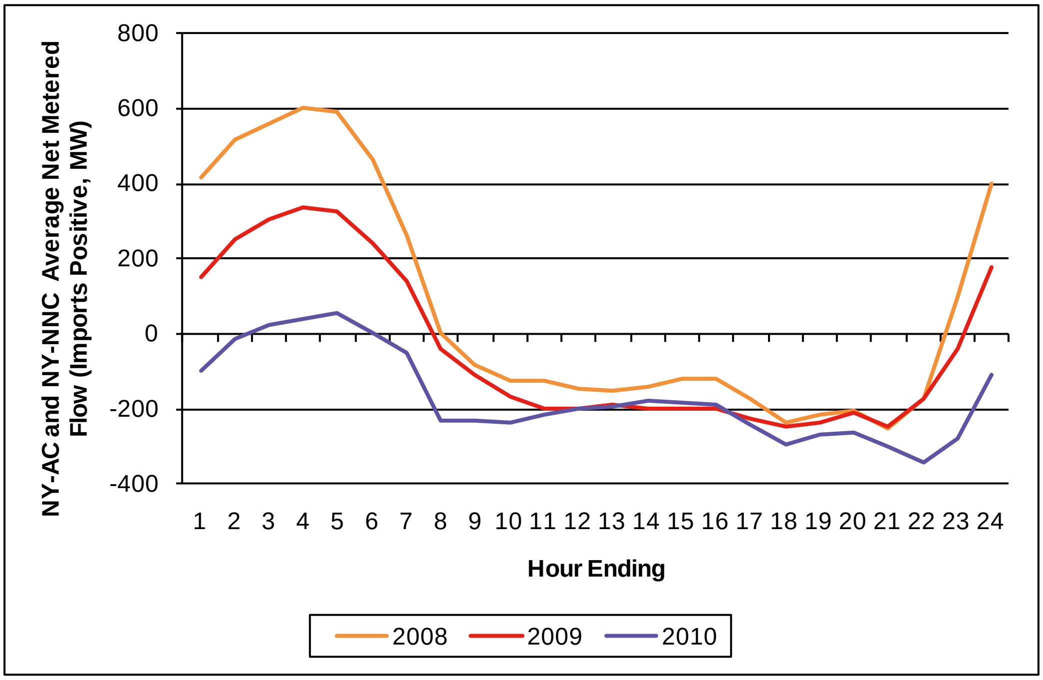

Figure 8-10: New York-AC ties, average net metered flow by hour of the day, 2008 to 2010.

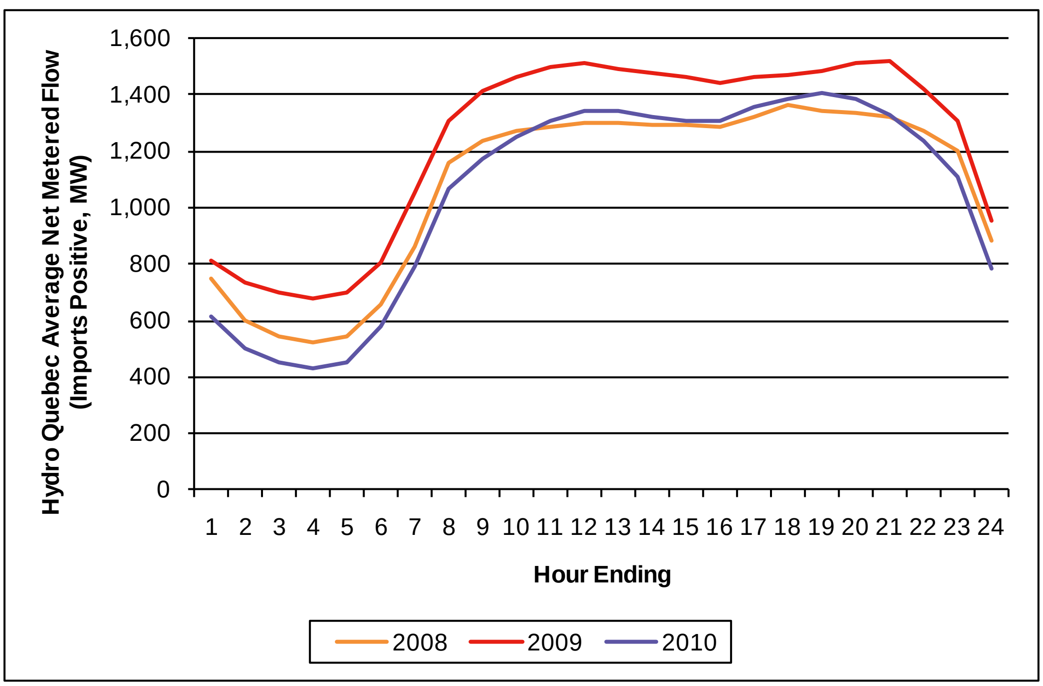

Figure 8-11: Hydro Québec (Phases 1 and 2 and Highgate), average net metered flow by hour of the day, 2008 to 2010.

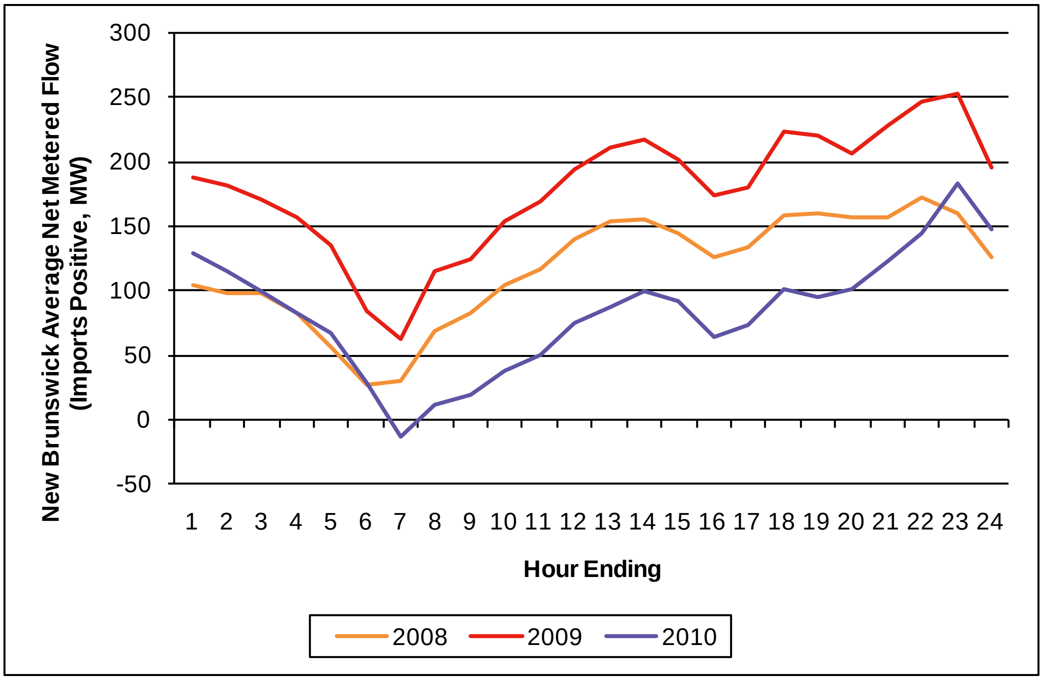

Figure 8-12: New Brunswick average net metered flow by hour of the day, 2008 to 2010.

8.1.4 Congestion and FTR

This section provides some details about the marginal cost of congestion and the marginal cost of losses by zone for the Day-Ahead and Real-Time Energy Markets, along with the Congestion Revenue Balancing Fund for 2010.

Table 8-8 and Table 8-9 show the annual average marginal congestion component and marginal loss component for the Hub and eight load zones.

Table 8-8
Average Day-Ahead Marginal Congestion Component, Marginal Loss Component, and Combined, 2010 ($/MWh)

Location/ Load Zone	Congestion Component	Marginal Loss Component	Congestion Component Plus Marginal Loss Component
Hub	−$0.13	$0.06	−$0.07
Maine	−$0.36	−$1.90	−$2.26
New Hampshire	−$0.37	−$0.56	−$0.94
Vermont	$0.00	$0.61	$0.61
Connecticut	$0.68	$1.12	$1.80
Rhode Island	−$0.40	−$0.46	−$0.85
SEMA	−$0.37	−$0.25	−$0.62
WCMA	$0.09	$0.47	$0.56
NEMA	−$0.32	−$0.42	−$0.74

Table 8-9
Average Real-Time Marginal Congestion Component, Marginal Loss Component, and Combined, 2010 ($/MWh)

Location/ Load Zone	Congestion Component	Marginal Loss Component	Congestion Component Plus Marginal Loss Component
Hub	−$0.03	$0.09	$0.06
Maine	−$0.37	−$2.07	−$2.43
New Hampshire	−$0.21	−$0.59	−$0.80
Vermont	$0.04	$0.36	$0.40
Connecticut	$0.20	$1.07	$1.27
Rhode Island	−$0.18	−$0.44	−$0.63
SEMA	−$0.14	−$0.07	−$0.21
WCMA	$0.14	$0.43	$0.57
NEMA	$0.04	−$0.30	−$0.26

Table 8-10 shows the monthly values of the different components of the Congestion Revenue Balancing Fund for 2010.

Table 8-10
Congestion Revenue Balancing Fund, 2010 ($, %)

Month	Fund Adj.	Day-Ahead Congestion Revenue	Real-Time Congestion Revenue	Negative Target Allocation (paid in by participants)	Positive Target Allocation (paid out to participants)	Monthly Fund Surplus or Shortfall	Amount Paid Out to Positive Target Allocations	Interest	FTR Capping	Ending Balance	Cumulative Balance for Year End	% Positive Allocation Paid
Jan	244	1,875,730	-6,853	832,267	−2,691,980	9,408	−2,691,980	318	0	9,725	9,725	100.00%
Feb	343	605,093	−62,341	360,691	−886,822	16,964	−886,822	188	5,426	17,153	26,878	100.00%
Mar	443	1,595,485	23,992	666,649	−2,641,642	−355,073	−2,286,569	4	0	4	26,882	86.56%
Apr	645	4,356,547	266,419	2,027,067	−6,477,476	173,201	−6,477,476	199	3,400	176,800	203,682	100.00%
May	289	7,220,377	304,381	5,023,005	−11,626,248	921,805	−11,626,248	802	0	922,607	1,126,290	100.00%
Jun	517	2,039,458	−82,128	974,830	−2,835,122	97,555	−2,835,122	771	0	98,326	1,224,615	100.00%
Jul	-20	3,475,998	231,297	1,789,455	−5,606,637	−109,906	−5,496,731	208	0	208	1,224,823	98.04%
Aug	216	6,171,813	−23,288	1,867,977	−7,168,060	848,658	−7,168,060	681	0	849,339	2,074,163	100.00%
Sep	30,211	3,302,309	63,409	1,874,297	−4,235,872	1,034,354	−4,235,872	846	3,154	1,038,354	3,112,517	100.00%
Oct	−91	3,066,234	16,066	667,516	−3,877,290	−127,565	−3,749,725	529	0	529	3,113,046	96.71%
Nov	−231	1,547,829	−31,644	806,759	−2,253,510	69,203	−2,253,510	713	6,233	69,917	3,182,962	100.00%
Dec	−354	2,064,973	−108,621	459,407	−3,049,734	−634,328	−2,415,406	541	0	541	3,183,503	79.20%

Table 8-11 shows demand-response assets and megawatts of participation during December 2010 by zone. Connecticut has the most megawatts enrolled, followed by Maine. Demand resources in Maine include several large industrial customers.

Table 8-11
Demand-Response Assets by Zone, December 2010

Zone	Real-Time Demand-Response Resource	Real-Time Emergency Generation Resource	On-Peak Demand Resource	Seasonal-Peak Demand Resource	Total
CT	333	339	91	236	999
ME	357	22	58	-	437
WCMA	169	69	70	19	327
NEMA	94	90	107	-	291
SEMA	72	49	65	3	189
NH	68	39	48	-	155
RI	60	44	48	1	153
VT	69	15	46	-	130
Total	1,222	667	533	259	2,681

8.2 Reserves Appendix

This reserves appendix provides information on the outcome of the payments and charges associated with the settlement of the Forward Reserve Market.

Table 8-12 shows the requirements, offers, and cleared amounts for each product and zone combination.

Table 8-12
Forward Reserve Market Requirements and
Participant Offers by Product and Reserve Zone (MW)

Forward-Reserve Period	Reserve Zone Name	TMNSR			TMOR		
		Req.	Offered	Cleared	Req.	Offered	Cleared
Summer 2010	System	900.0	N/A	N/A	700.0	N/A	N/A
	ROS	N/A	1,728.0	768.0	798.0	190.0	30.0
	SWCT	N/A	0	0	587.0	402.0	402.0
	CT	N/A	310.6	310.6	1,225.0	549.0	512.0
	NEMA/Boston	N/A	0	0	N/A	0	0
Winter 2010/2011	System	850.0	N/A	N/A	750.0	N/A	N/A
	ROS	N/A	1,339.0	704.0	720.0	213.0	13.0
	SWCT	N/A	0	0	508.0	422.0	236.0
	CT	N/A	419.8	354.8	925.0	591.0	334.0
	NEMA/Boston	N/A	0	0	0	0	0

Table 8-13 shows forward-reserve megawatts designated to meet forward-reserve requirements in each reserve zone for 2008 to 2010 categorized by generator technology.[168]

Table 8-13
Forward Reserve Delivered,
by Technology Type, 2008 to 2010

Technology Type	2008	2009	2010
Hydro	23.0%	22.8%	19.1%
Non-fast-start	1.5%	2.7%	5.3%
Fast-start	75.5%	74.5%	75.6%

Table 8-14 shows the monthly average bilateral trading volume of forward-reserve obligations for 2008 to 2010. The volumes shown do not include prearranged transactions among affiliates occurring at the start of the season.

Table 8-14
Monthly Average Bilateral FRM Obligation Trading Volume, 2008 to 2010 (MW)

Year	Systemwide TMOR	Systemwide TMNSR	SWCT TMOR	CT TMOR	NEMA/Boston TMOR
2008	0	179	0	0	7
2009	3	214	69	0	0
2010	2	1,304	84	0	0

Figure 8-13 shows monthly average peak-hour reserve margins for TMSR and TMNSR for 2009 and 2010.

[168] Forward-reserve auctions clear on a portfolio basis (i.e., without specifying resources). Resources are designated before the start of the operating day at 12:00 a.m. (midnight).

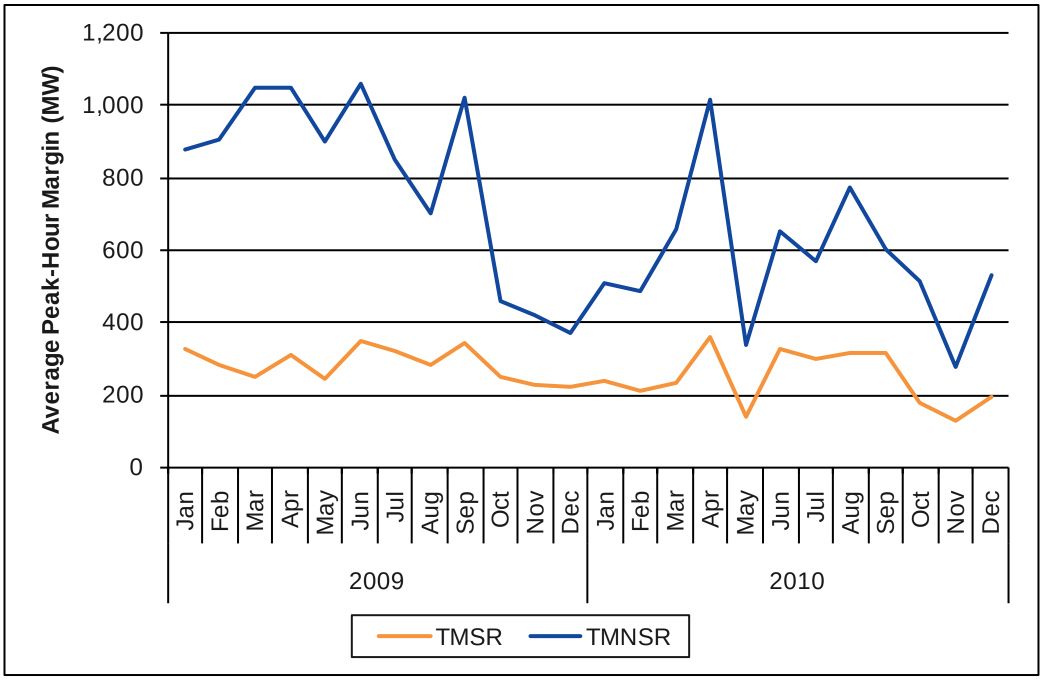

Figure 8-13: Real-time reserve margins, TMSR and TMNSR, peak hour, 2009 to 2010.

Table 8-15 shows the total failure-to-reserve penalties by participants with forward-reserve obligations during 2008 through 2010.

Table 8-15
Failure-to-Reserve Penalties, 2008 to 2010 ($)

Year	Systemwide TMNSR	Systemwide TMOR	SWCT TMOR	CT TMOR	NEMA/Boston TMOR
2008	−3,517,805	−52,591	−1,664,859	−1,536,191	−911,575
2009	−1,426,316	−68,489	−2,082,158	−405,945	−61,431
2010	−3,212,153	−21,502	−1,306,587	−521,634	0

Total forward- and real-time reserve payments and penalties are shown in Table 8-16. The net forward credit equals the forward-reserve payments minus penalties and forward-reserve energy obligation charges.

Table 8-16
Forward and Real-Time Reserve Payments and Penalties, 2008 to 2010 ($)

Year	Failure-to-Activate Penalties	Failure-to-Reserve Penalties	Forward Credit	Forward-Reserve Obligation Charge	Net Forward Credit	Real-Time Credit
2008	−10,752	−7,683,020	179,551,242	−1,543,901	171,049,377	16,799,082
2009	−8,367	−4,044,339	148,172,068	−1,432,877	144,119,362	7,852,066
2010	−87,510	−5,061,876	118,543,183	−2,417,082	113,393,797	18,742,645

Table 8-17 shows total reserve charges for the reporting period that are allocated real-time load obligation.

Table 8-17
Reserve Charges to Load, by Load Zone, 2010 ($)[(a)]

Market	Product	CT Load Zone	NEMA Load Zone	Rest-of-System
Forward reserves	TMNSR	10,541,911	1,148,680	11,122,011
Forward reserves	TMOR	73,181,437	0	17,399,758
Real-time reserves	TMNSR	1,192,367	976,594	2,750,829
Real-time reserves	TMOR	369,710	283,373	756,556
Real-time reserves	TMSR	2,461,426	2,022,085	5,512,622

(a) The SWCT reserve zone does not have a separate allocation.

8.3 Regulation Appendix

This section presents additional detail on the requirements, payments, and compliance of the ISO's Regulation Market during 2010.

Table 8-18 summarizes information about clearing prices in the Regulation Market by month for 2010.

Table 8-18
Monthly Regulation Clearing Price Statistics, 2010 ($)

Month	Minimum	Average	Maximum
Jan	$0.00	$8.37	$82.24
Feb	$1.17	$8.05	$28.33
Mar	$0.00	$8.14	$76.67
Apr	$0.00	$7.13	$22.49
May	$3.64	$7.25	$61.69
Jun	$3.00	$6.54	$59.59
Jul	$0.00	$6.37	$20.00
Aug	$0.00	$6.25	$56.59
Sep	$2.99	$6.58	$80.00
Oct	$4.13	$6.29	$10.50
Nov	$3.33	$6.49	$13.83
Dec	$3.00	$7.41	$30.00

Figure 8-14 shows the NERC CPS 2 compliance requirement and the monthly ISO compliance levels for 2010.

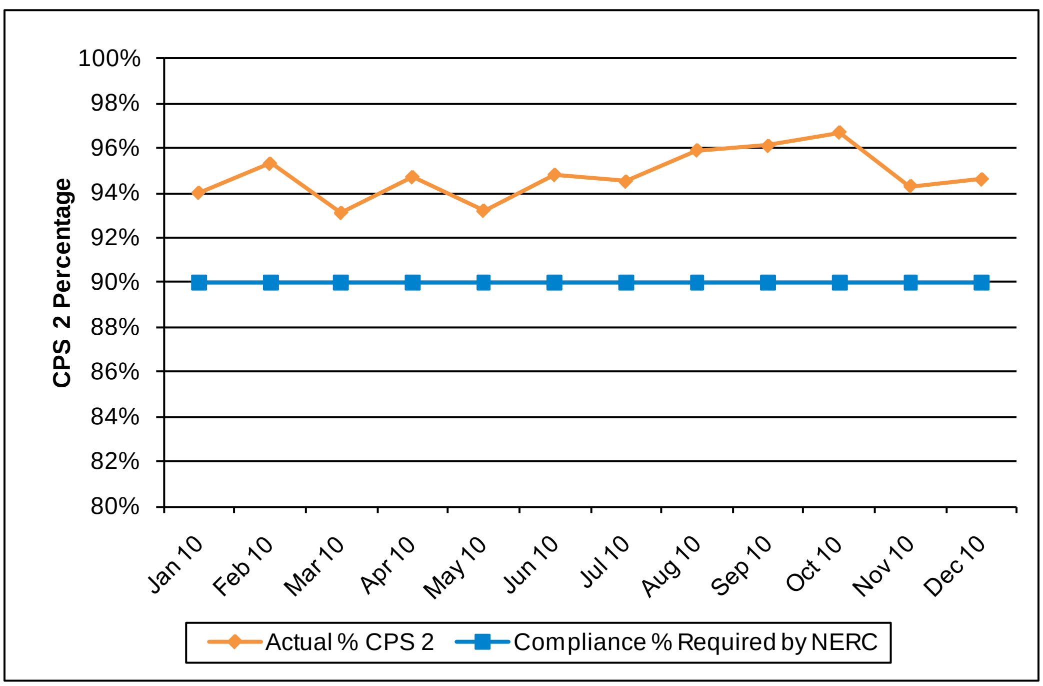

Figure 8-14: CPS 2 compliance, 2010.

Figure 8-15 shows the megawatt time-weighted monthly average of the regulation requirements for 2008 to 2010.

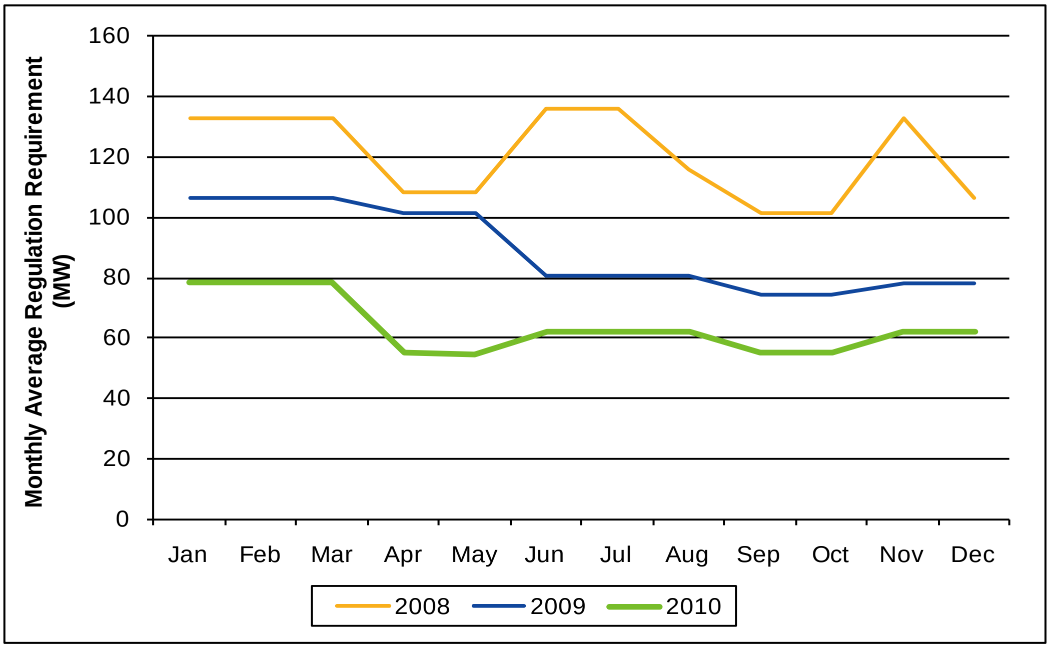

Figure 8-15: Monthly average regulation requirements, 2008 to 2010.

Figure 8-16 shows the annual average regulation requirement since 2002. Average regulation values have fallen from 181 to 64 MW during the last eight years.

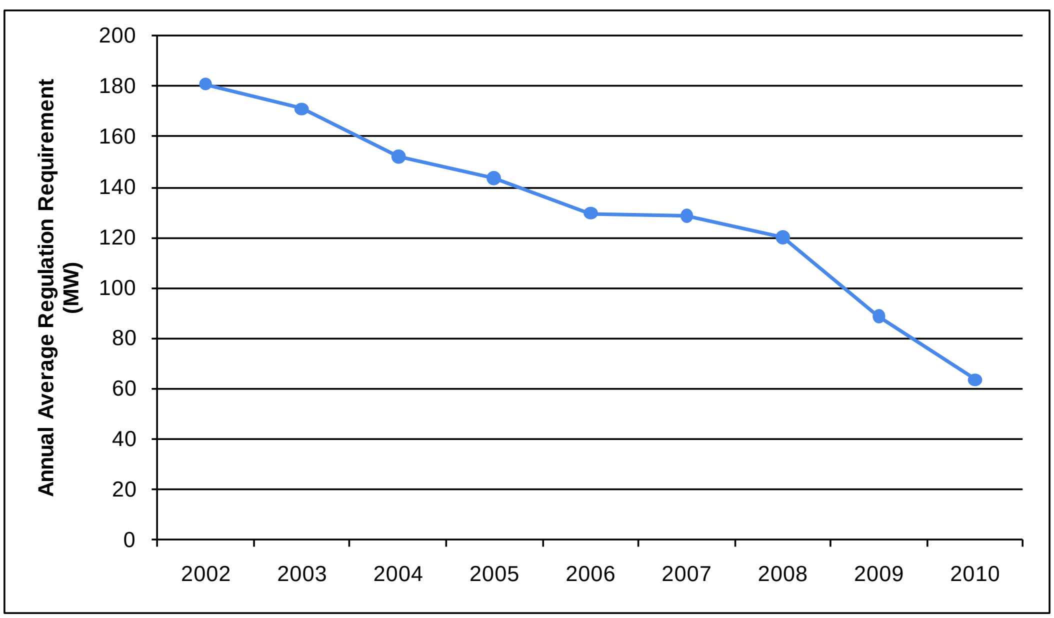

Figure 8-16: Annual average regulation requirement, 2002 to 2010.

Figure 8-17 shows the total 2009 and 2010 Regulation Market payments by payment category.

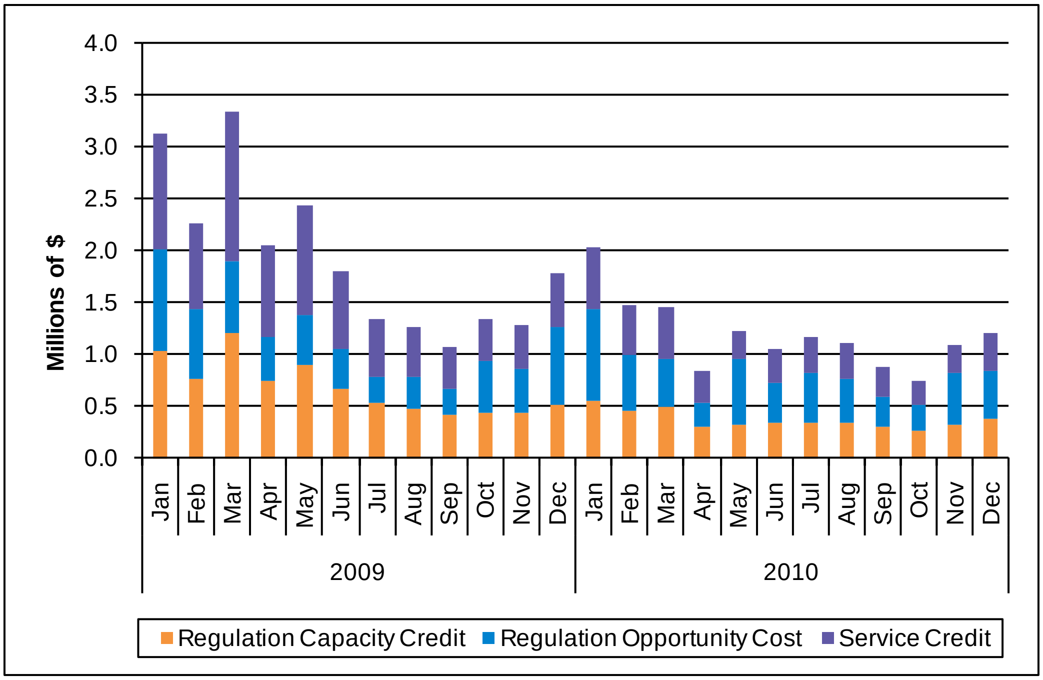

Figure 8-17: Total regulation payments by month, 2009 to 2010.

Figure 8-18 shows in-service regulation capability by month for 2010.

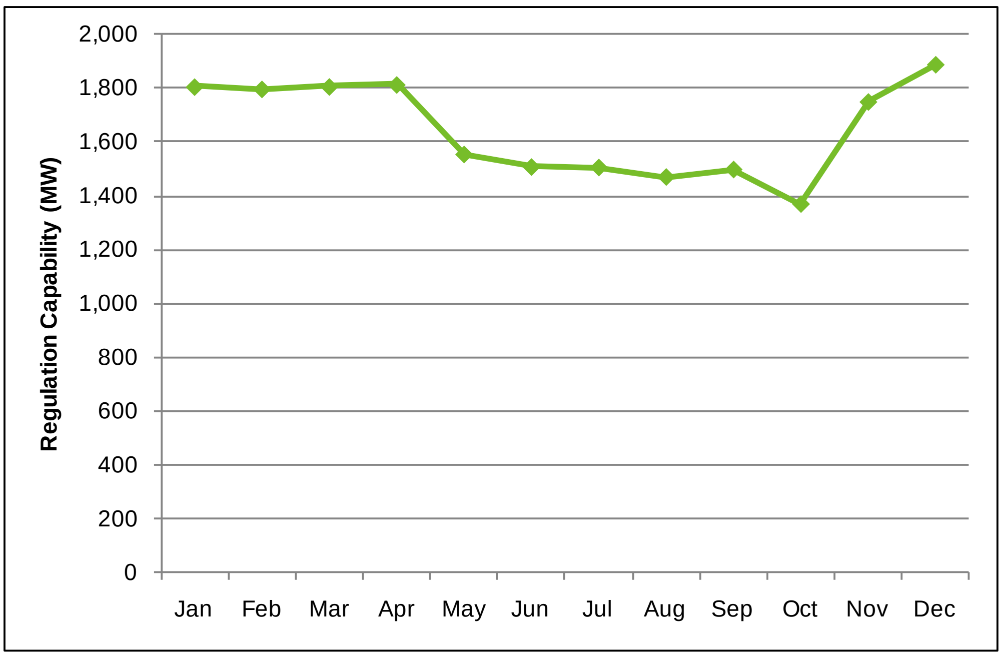

Figure 8-18: Total available in-service regulation capability, 2010.

Figure 8-19 shows the percentage of regulation capacity and the percentage of regulation provided by unit type for 2010.

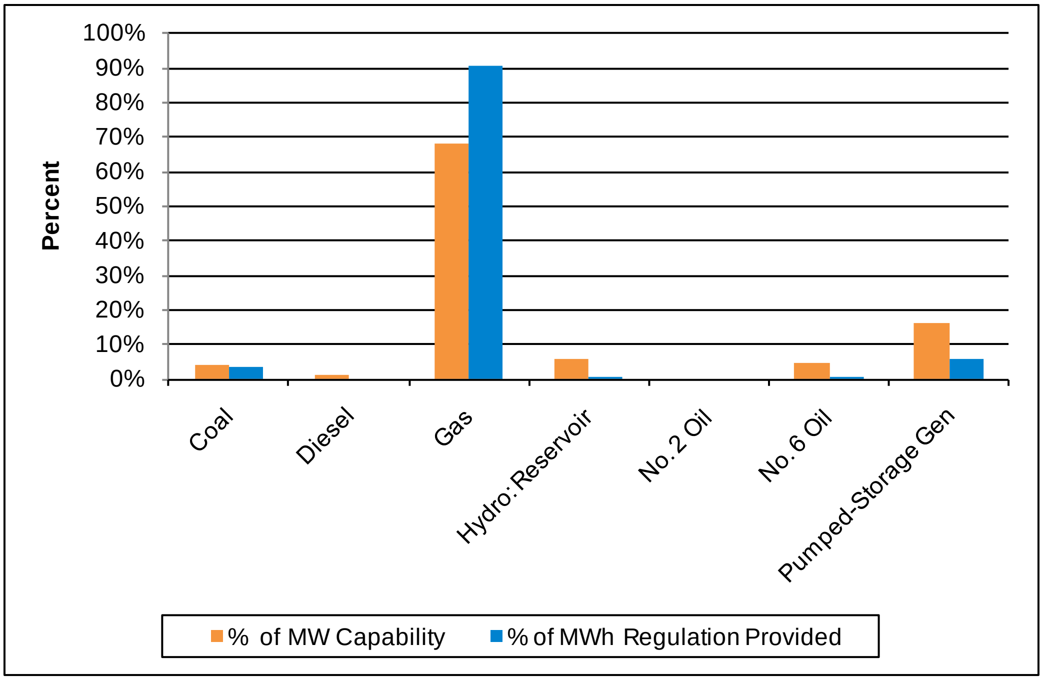

Figure 8-19: Regulation capability and regulation provided by fuel type, 2010.

8.4 Reliability Agreements

Table 8-19 shows each zone's 2010 seasonal claimed capability (SCC), the total capacity of resources in each zone with cost-of-service Reliability Agreements, and payments associated with each zone.[169]

[169] *Claimed capability* is a generator's maximum production or output.

Table 8-19
Percentage of Capacity under Reliability Agreements, Effective February 2010

Load Zone	2010 CELT Summer Seasonal Claimed Capability (MW)	2010 Capacity with Cost-of-Service Reliability Agreement	2010 Capacity under Reliability Agreements as % of 2010 SCC	2010 Reliability Agreement Payments ($)
Maine	3,071	0	0.0%	0
New Hampshire	4,118	0	0.0%	0
Vermont	887	0	0.0%	0
Connecticut	7,346	2,172	29.6%	5,730,617
Rhode Island	2,586	0	0.0%	0
SEMA	6,026	0	0.0%	0
WCMA	2,769	538	19.4%	5,880,217
NEMA	3,340	0	0.0%	0
New England total	30,142	2,710	9.0%	11,610,834

Sources: *Reliability Agreement Status Summary* (http://www.iso-ne.com/genrtion_resrcs/reports/rmr/reliability_ agreement_status_summary.ppt),*SCC Monthly Report January 2011* (http://www.iso-ne.com/genrtion_resrcs/snl_ clmd _cap/2011/scc_january_2011.xls).

8.5 Reliability and Operations Assessment Appendix

This section includes information on net Reliability Agreement and tariff charges, as well as a listing of hours the system was under Minimum Generation Emergency events or M/LCC2. Table 8-20 shows the annual sum of monthly net payments for 2008 through 2010.

Table 8-20
Net Reliability Agreement Payments, System Total (Million $)[a, b]

	2008	2009	2010
Payment	124.68	84.93	10.90

(a) The table shows restated values for previous years that account for the refunds to load associated with the FERC settlements.

(b) Values represent reliability payments with interest.

Total payments under each ISO schedule are shown in Table 8-21.

Table 8-21
ISO Self-Funding Tariff Charges ($)

Date	Schedule 1: Scheduling, System Control, and Dispatch Service	Schedule 2: Energy Administration Service	Schedule 3: Reliability Administration Service
2010 Total	$37,578,933.85	$56,496,936.31	$51,889,696.22

Total payments under each OATT schedule are shown in Table 8-22.

Table 8-22
OATT Charges ($)

Date	Schedule 1	Schedule 2: CC	Schedule 2: VAR	Schedule 8: TOUT	Schedule 9: RNS	Schedule 16: Black Start	Schedule 19: SCR
2010 Total	$35,663,393.06	$22,682,573.36	$5,188,673.89	$13,069,128.52	$1,328,292,459.46	$10,353,572.07	$1,635,374.74

Table 8-23 and Table 8-24 summarize the periods when OP 4, M/LCC2, and Minimum Generation Emergency events were declared in 2010 to maintain system reliability.

Table 8-23
M/LCC2 and OP 4 Events, 2010

Date	Event	Area Effected
Jan 12	M/LCC2	New Hampshire
Jan 17	M/LCC2	All of New England for Capacity
Feb 02	M/LCC2	All of New England for Capacity
Feb 04	M/LCC2	All of New England for Capacity
Feb 06	M/LCC2	All of New England for Capacity
Feb 16	M/LCC2	All of New England for Capacity
Feb 27	M/LCC2	All of New England for Capacity
Feb 28	M/LCC2	All of New England for Capacity
Mar 06	M/LCC2	All of New England for Capacity
Mar 14	M/LCC2 / OP 4	All of New England for Capacity
Mar 27	M/LCC2	All of New England for Capacity
Apr 01	M/LCC2	All of New England for Capacity
May 02	M/LCC2 / OP 4	All of New England for Capacity
May 03	M/LCC2	All of New England for Capacity
May 08	M/LCC2	All of New England for Capacity
May 15–16	M/LCC2	All of New England for Capacity
May 24	M/LCC2	All of New England for Capacity
May 26	M/LCC2 / OP 4	All of New England for Capacity
May 29	M/LCC	All of New England for Capacity
Jun 24	M/LCC2 / OP 4	All of New England for Capacity
Jul 05	M/LCC2 / OP 4	All of New England for Capacity
Jul 06	M/LCC2	All of New England for Capacity
Jul 07	M/LCC2	All of New England for Capacity
Aug 09	M/LCC2 / OP 4	All of New England for Capacity
Aug 31	M/LCC2	All of New England for Capacity
Sep 02	M/LCC2	All of New England for Capacity
Dec 10	M/LCC2	All of New England for Capacity

Table 8-24
Minimum Generation Emergency Events, 2010

Date	Hours Declared
Jan 26	2:00 a.m.–5:00 a.m.
Mar 21	5:00 a.m.–8:00 a.m.
Mar 25	2:00 a.m.–4:00 a.m.
Mar 26	midnight–4:00 a.m.
Jun 9	3:00 a.m.–5:00 a.m.
Jun 13	6:00 a.m.–8:00 a.m.
Jun 14	2:00 a.m.–5:00 a.m.
Jun 18	3:00 a.m.–6:00 a.m.
Aug 19	3:00 a.m.–5:00 a.m.
Aug 24	2:30 a.m.–6:00 a.m.
Aug 29	3:00 a.m.–8:00 a.m.
Oct 2	4:00 a.m.–6:00 a.m.
Oct 4	3:00 a.m.–5:00 a.m.

Cumulative frequency distributions show that surplus conditions are occurring less frequently. Table 8-25 shows a summary of main statistics of the cumulative frequency distribution of average hourly surplus for all hours and for only peak hours.

Table 8-25
Major Statistics on Cumulative Frequency Distribution of Surplus, All Hours and Peak Hours, 2008 to 2010 (MW)

Statistic	All Hours			Peak Hours		
	2008	2009	2010	2008	2009	2010
Max	6,902	5,641	5,065	2,849	1,780	1,876
Mean	1,408	996	886	661	374	259
Min	−475	−611	−691	−141	−298	−675
Standard Deviation	987	875	860	497	374	328
5th percentile	158	17	−20	61	−42	−106
10th percentile	325	85	54	127	−11	-40
50th percentile	1,176	740	624	519	283	182
75th percentile	2,031	1,547	1,318	925	585	437
90th percentile	2,792	2,316	2,190	1,349	859	694
95th percentile	3,230	2,724	2,660	1,642	1,099	869
99th percentile	4,186	3,443	3,476	2,368	1,628	1,194

List of Acronyms and Abbreviations

Acronyms and Abbreviations	Description
AC	alternating current
ACE	area control error
AMR	Annual Markets Report
APR	Alternative Pricing Rule
ARR	Auction Revenue Rights
BAL-001-0	NERC's *Real Power Balancing Control Performance Standard*
Btu	British thermal unit
CCGT	combined-cycle gas turbine
CELT Report	ISO annual report on capacity, energy, load, and transmission
CONE	cost of new entry
CPS 2	NERC *Control Performance Standard 2*
CRBF	Congestion Revenue Balancing Fund
CSC	Cross-Sound Cable
CSO	capacity supply obligation
CT	State of Connecticut, Connecticut load zone, Connecticut reserve zone
DALRP	Day-Ahead Load Response Program
DDP	desired dispatch point
DOJ	US Department of Justice
EAS	Energy Administration Service
ecomax	economic maximum
ecomin	economic minimum
EMM	External Market Monitor
EPAct	*Energy Policy Act of 2005*
ERCOT	Electric Reliability Council of Texas
F	Fahrenheit
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission

Acronyms and Abbreviations	Description
FRM	Forward Reserve Market
FTR	Financial Transmission Right
GWh	gigawatt-hour
HE	hour ending
HHI	Herfindahl-Hirschman Index
Highgate	Vermont–Hydro Quebec Interconnection
HQICC	Hydro-Québec Phase I/II Interface
ICAP	installed capacity
ICE	Intercontinental Exchange, Inc.
ICR	Installed Capacity Requirement
IMM	Internal Market Monitor
ISO	Independent System Operator; ISO New England
kW	kilowatt
kWh	kilowatt-hour
kW-mo	kilowatt-month
L_{10}	Limit 10
LMP	locational marginal price
LOLE	loss-of-load expectation
LSCPR	local second-contingency protection resource
LSE	load-serving entity
LSR	local sourcing requirement
MCL	maximum capacity limit
ME	State of Maine and Maine load zone
M/LCC	Master/Local Control Center
M/LCC2	Master/Local Control Center Procedure No. 2, *Abnormal Conditions Alert*
MMBtu	million British thermal units
MW	megawatt
MWh	megawatt-hour
N-1	first contingency
N-1-1	second contingency

Acronyms and Abbreviations	Description
NCPC	Net Commitment-Period Compensation
NEL	net energy for load
NEMA	Northeast Massachusetts and Boston load zone
NEMA/Boston	Northeast Massachusetts/Boston local reserve zone
NERC	National Electric Reliability Corporation
NH	State of New Hampshire and New Hampshire load zone
NICR	net Installed Capacity Requirement (net of the HQ interconnection credits)
NNC	Norwalk Harbor–Northport, NY, Cable (formerly called the New York 1385 transmission line)
NPCC	Northeast Power Coordinating Council
NTA	negative target allocation
NY	State of New York
NYISO	New York Independent System Operator
NY-NNC	Norwalk Harbor–Northport, NY, Cable (formerly called the New York 1385 transmission line)
NY-AC	New York Alternating-Current Interface
NY-CSC	New York Cross-Sound Cable
O&M	operations and maintenance
OATT	*Open Access Transmission Tariff*
ODR	other demand resources
OOM	out of market
OP 4	ISO Operating Procedure No. 4
OP 8	ISO Operating Procedure No. 8
PER	peak energy rent
PJM	PJM Interconnection, L.L.C.
pnode	pricing node
PRD	price-responsive demand
PTA	positive target allocation
PTF	pool transmission facility
Q	quarter
QUA	Qualified Upgrade Award

Acronyms and Abbreviations	Description
QWLI	Quantity-Weighted Lerner Index
RAA	Reserve Adequacy Analysis
RAS	Reliability Administration Service
RCP	regulation clearing price
RCPF	Reserve Constraint Penalty Factor
RFP	request for proposals
RI	State of Rhode Island and Rhode Island load zone
RNS	Regional Network Service
ROS	Rest-of-System reserve zone
RSI	Residual Supply Index
RSP	Regional System Plan
RTDR	real-time demand response
RTEG	real-time emergency generation
RTLO	real-time load obligation
RTO	Regional Transmission Organization
RTPR	real-time price response
SCC	seasonal claimed capability
SCR	special-constraint resource
SEMA	Southeast Massachusetts load zone
SMD	Standard Market Design
SOI	show of interest
SPD	scheduling. pricing, and dispatch
SWCT	Southwest Connecticut
TMNSR	10-minute nonspinning reserve
TMOR	30-minute operating reserve
TMSR	10-minute spinning reserve
TOUT	through-or-out service
UCAP	unforced capacity
UDS	unit dispatch and scheduling
VAR	voltage ampere reactive (voltage control)

Acronyms and Abbreviations	Description
VT	Vermont and Vermont load zone
WCMA	Western/Central Massachusetts
WEAF	Weighted Equivalent Availability Factors