2008 Annual Markets Report

Markets Monitoring and Mitigation
June 16, 2009

Preface

The Internal Market Monitoring Unit (INTMMU) of ISO New England (ISO) publishes an Annual Markets Report that assesses the state of competition in the wholesale electricity markets operated by the ISO. The *2008 Annual Markets Report* covers the ISO's most recent operating year, January 1 to December 31, 2008. The report addresses the development, operation, and performance of the wholesale electricity markets administered by the ISO and presents an assessment of each market based on market data, performance criteria, and independent studies.

This report fulfills the requirement of *Market Rule 1*, Section 11.3, Appendix A, *Market Monitoring, Reporting, and Market Power Mitigation*:

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

This report of the INTMMU presents the most important findings, market outcomes, and market design changes of New England's wholesale electricity markets for 2008. 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, out-of-merit generation for meeting reliability criteria, and the INTMMU's operations. An appendix provides additional data on the electric energy and reserves markets. A list of acronyms and abbreviations also is included. Key terms are italicized and defined within the text and footnotes.

[1] FERC, Electric Tariff No. 3, Section III, *Market Rule 1*, *Standard Market Design*, Appendix A: Market Monitoring, Reporting and Market Power Mitigation, III.A.11—Reporting (effective July 1, 2005).

[2] 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 2008

When wholesale electricity markets are competitive and efficient, they provide the incentives needed to maintain an adequate supply of electric energy, over the long run, at prices that are consistent with, but not higher than the cost of providing it. One of the core responsibilities of the ISO New England (ISO) Internal Market Monitoring Unit (INTMMU) is to review the competitiveness of the wholesale electricity markets. The INTMMU analyzed the 2008 performance of the region's wholesale electric energy, regulation, and reserve markets using supply offers, demand bids, economic data, fuel prices, market results, and other information regarding the wholesale electric markets in 2008.[3] The results of these analyses indicate that the outcomes of the wholesale electric power markets in New England were consistent with competitive markets. The INTMMU also determined and filed reports with the Federal Energy Regulatory Commission (FERC) that the two Forward Capacity Auctions (FCAs) that took place during 2008 were competitive.

The key results and major findings for the wholesale markets in 2008 concern the price of electric energy compared with past years' prices; higher, more volatile fuel prices and their impact on electricity prices; and a reduction in the consumption of electric energy. In 2008 in New England, the average real-time price of electric energy at the Hub rose 21% over 2007 levels to $80.56/megawatt-hour (MWh).[4] This was driven by a 25% increase in the cost of natural gas and a 42% increase in the cost of No. 6 oil.[5] Average annual fuel prices for 2008 were the highest since New England restructured its wholesale electric markets in 1999.

High average fuel prices were accompanied by significant volatility in 2008. The monthly average natural gas price in New England was $11.06/million British thermal units (MMBtu) in January. It rose to $13.41/MMBtu in June and then dropped to $7.58/MMBtu by December. Because fuel prices drive electricity prices, average monthly electricity prices followed the same pattern.

The increase in electricity prices was moderated by a drop in electric energy consumption of about 2% in 2008. This drop was caused by three factors—a decline in economic activity, more efficient use of electricity, and higher prices—and means that electric energy consumption still is below its annual maximum, which was reached in 2005.

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[3] *Regulation* is the capability of specially equipped generators to increase or decrease their generation output every four seconds in response to signals they receive from the ISO to control slight changes on the system.

[4] (1) The *Hub* is a collection of locations for which the ISO calculates and publishes wholesale prices for electric energy. The Hub price is intended to represent an uncongested price for electric energy (i.e., when there is no congestion on the transmission system). (2) This report includes a number of different methodologies to represent annual average system prices as part of different analyses. The $80.56/MWh value is a simple average of the Real-Time Energy Market Hub prices, which gives a general description of the of price levels over the year. Other methods to describe average system prices include a zonal load weighting of zonal prices that is used in the all-in cost metric ($80.75/MWh) and a system load-weighted average of Hub prices that is used in the fuel-adjusted price and competitive benchmark analyses ($83.91/MWh).

[5] 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.

The two FCAs that were held in 2008 are important milestones in the evolution of the region's wholesale electricity markets, representing the culmination of a process that began with a FERC order in late 2002.[6] The INTMMU reported on the first auction in the *2007 Annual Markets Report* (AMR07).[7] The second auction (FCA #2) cleared 4,755 MW more than the Installed Capacity Requirement (ICR) of 32,528 MW.[8] The total cleared amount included 2,778 MW of demand resources, an increase of 499 MW of demand resources compared with the first auction.[9] The growth in demand resources began in December 2006 with the start of Forward Capacity Market (FCM) transition payments.[10] The total amount of demand resources at the end of FCA #2 is a significant percentage of the region's resources and will require significant effort to integrate reliably into system operations and dispatch.

The *2008 Annual Markets Report* addresses the development, operation, and performance of the wholesale electricity markets administered by ISO New England and presents an assessment of each market based on market data, performance criteria, and independent studies. This section summarizes the key market results and findings for 2008 and the assessment of each market. A discussion of how the markets work and market oversight is included in Section 2. Section 3 through Section 7 contain a more thorough discussion of the 2008 market results. Results from the electric energy, capacity, reserve, and regulation markets are presented. Data on the generator commitments made for reliability and information on the INTMMU's operation also are included. Section 8 is an appendix of additional data from the energy and reserves markets. 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 Energy Markets

The factors affecting the national economy in 2008 also affected the wholesale electric energy markets in New England. High fuel prices through most of the summer resulted in high electricity prices. The decline in economic activity throughout the year, the more efficient use of electricity overall, and the higher prices resulted in a decrease in energy consumption for the year. This section presents these and other highlights of the wholesale electric energy markets in 2008.

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[6] *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), p. 37. For background information, see *Explanatory Statement in Support of Settlement Agreement of the Settling Parties and Request for Expedited Consideration and Settlement Agreement Resolving All Issues,* FERC Docket Nos. ER03-563-000, -030, -055 (filed March 6, 2006; as amended March 7, 2006).

[7] The ISO's AMR07 is available online at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html.

[8] The *Installed Capacity Requirement* is the total amount of installed capacity the system needs to meet the Northeast Power Coordinating Council (NPCC)'s loss-of-load expectation (LOLE) criterion to not disconnect load more than one time in 10 years. For additional information on the LOLE criterion, refer to NPCC Document A-02, *Basic Criteria for Design and Operation of Integrated Power Systems* (New York: NPCC Inc., 2004); http://www.npcc.org/documents/regStandards/Criteria.aspx.

[9] *Demand resources* include installed measures, such as equipment, services, and strategies, that result in additional and verifiable reductions in end-use demand on the electricity network during specific performance hours.

[10] The first year of service for FCM resources does not begin until June 2010, so these resources are being paid a transition payment for maintaining their availability and developing new capacity. The FCM Settlement Agreement (cited below) specifies paying all capacity a flat rate until June 1, 2010. After the transition period ends, resources with capacity obligations obtained in the FCAs will be paid the auction clearing prices.

1.1.1 Annual All-In Wholesale Electricity Cost

The all-in wholesale electricity cost is an estimate of the total wholesale market cost of electric energy in $/MWh.[11] It includes electric energy costs, daily reliability costs, capacity costs, Regulation Market costs, reserve market costs, and the cost of FERC-approved Reliability Cost-of-Service Agreements (Reliability Agreements). Figure 1-1 shows the average annual all-in wholesale electricity cost metric and natural gas prices for 2005 through 2008.

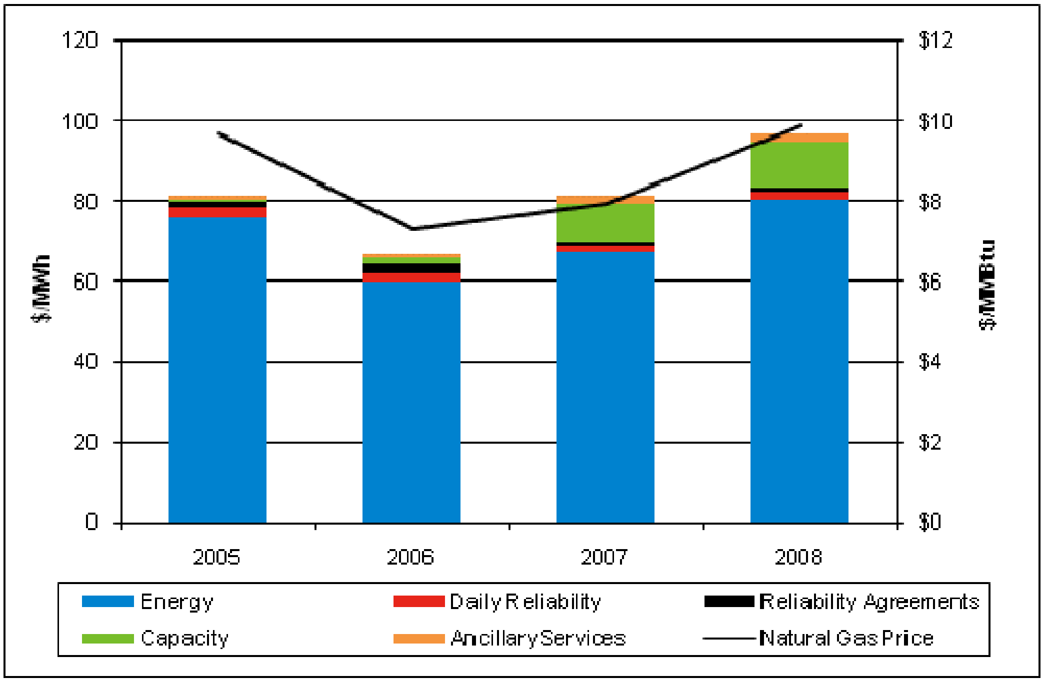

Figure 1-1: All-in cost for electricity.

Note: The daily reliability and Reliability Agreement costs are allocated systemwide to enable a regionwide rate to be calculated. These costs actually are allocated to the load zone in which they occur. New England is divided into the following load zones: Maine, New Hampshire, Vermont, Rhode Island, Connecticut (CT), Western/Central Massachusetts (WCMA), Northeast Massachusetts and Boston (NEMA), and Southeast Massachusetts (SEMA). (New England also is divided into reserve zones [see Section 1.1.9] and capacity zones [see Section 1.3.2.])

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

The all-in cost rose from $81.49/MWh in 2007 to $96.89/MWh in 2008, an increase of $15.40/MWh or 19%. Of this $15.40/MWh increase, 86% was the result of increased electric energy costs, which were driven by increases in fuel prices. The capacity costs prescribed by a Settlement Agreement for the Forward Capacity Market accounted for 12% of the increase; transition payments prescribed by the FCM agreement increased from $3.05/kW-month to $3.75/kW-month on June 1, 2008. The remaining 2% was spread among the costs for daily reliability, Reliability Agreements, and ancillary services (e.g., regulation service and reserves).

[11] 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 1.1.4 and Section 3.3.2, and the simple average of Hub prices shown earlier. This analysis uses this metric of zonal load-weighted averages of zonal prices because it better represents the prices load actually paid. The ISO publishes a separate wholesale load cost metric that includes only costs allocated to real-time load obligations.

The main factors that affected the increase in the all-in cost for electricity in 2008—the decrease in consumption and the increase in electric energy costs driven by the increase in fuel prices—are addressed in the following subsections.

1.1.2 Demand for Electricity

Table 1-1 shows that actual and weather-normalized electricity consumption each decreased by about 2% from 2007 to 2008.[12] Annual electricity consumption has not yet regained its 2005 level of 136.4 gigawatt-hours (GWh). The drop in electric energy consumption from 2007 was caused by three factors: a decline in economic activity, more efficient use of electricity, and higher prices. In contrast to the decline in energy consumption, weather-normalized peak demand increased. This increase means that the region's load factor continued to decline in 2008.[13]

Table 1-1
Annual and Peak Electric Energy Statistics, 2005 to 2008

	2005	2006	2007	2008	% Change 2007–2008
Annual NEL (GWh)[(a)]	136,355	132,087	134,466	131,736	−2.0%
Normalized NEL (GWh)	134,347	132,547	134,109	131,501	−1.9%
Recorded peak demand (MW)	26,885	28,130	26,145	26,111	−0.1%
Normalized peak demand (MW)	26,545	26,940	27,460	27,765	1.1%

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

1.1.3 Fuel Prices and Electricity Prices in 2008

The average annual price of electric energy, which is 83% of the all-in cost, rose by 21% in 2008. The increase in the cost of electric energy was caused by increases in the cost of natural gas, which rose 25% in 2008, and in the cost of No. 6 oil, which rose 42% in 2008. Natural gas price increases translate directly into wholesale electric energy price increases because natural gas often is the marginal fuel in the region, setting the wholesale electricity price about 62% of the time in 2008.

New England electricity prices rapidly adjust to changes in fuel markets. Figure 1-2, which shows the percentage change in monthly natural gas prices and the percentage change in monthly real-time locational marginal prices (LMPs), demonstrates that changes in electricity prices are nearly the same as changes in natural gas prices.[14] The deviation from the pattern in August and September was caused by a higher-load period in 2007, when more expensive oil-fired units were needed to meet demand and set the price.

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

[13] The *load factor* is the ratio of average hourly demand during a year to the peak hourly demand.

[14] *Locational marginal pricing* is a way to efficiently capture the impacts that locational variations in supply, demand, and transmission limitations at every location on the system have on electric energy prices.

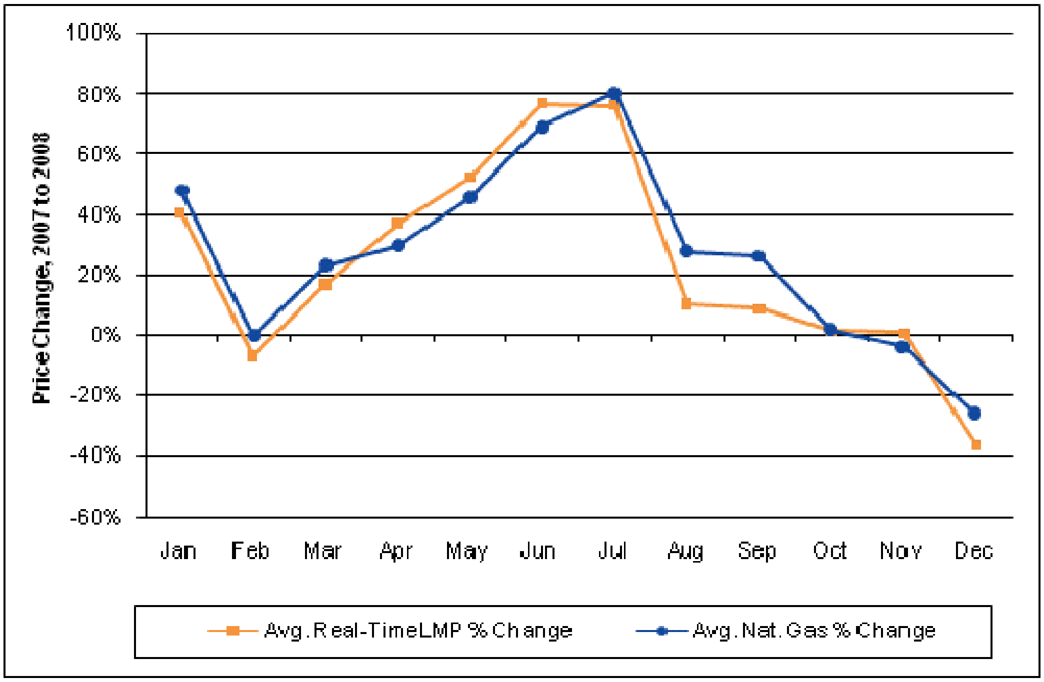

Figure 1-2: Percentage change in real-time locational marginal prices and natural gas, 2007 to 2008.

Sources: Natural gas price information provided by ICE.

1.1.4 Fuel-Adjusted Price

The INTMMU calculated the 2008 fuel-adjusted electricity price by adjusting the 2008 marginal LMPs by the ratio of the 2008 daily fuel prices to the year 2000 average monthly fuel prices of the corresponding market intervals and marginal fuel types. The results of this approach indicate the impact of fuel prices on electricity prices but only provide a rough estimate because it does not account for the impact that changes in relative fuel prices, load growth, and resource mix since the year 2000 have had on system dispatch and pricing. Figure 1-3 shows average actual and fuel-adjusted real-time electric energy prices for 2000 to 2008. High fuel prices in 2005, caused in part by Hurricanes Katrina and Rita, caused the large price increase in that year. Changes since 2005 also are largely driven by fuel prices.

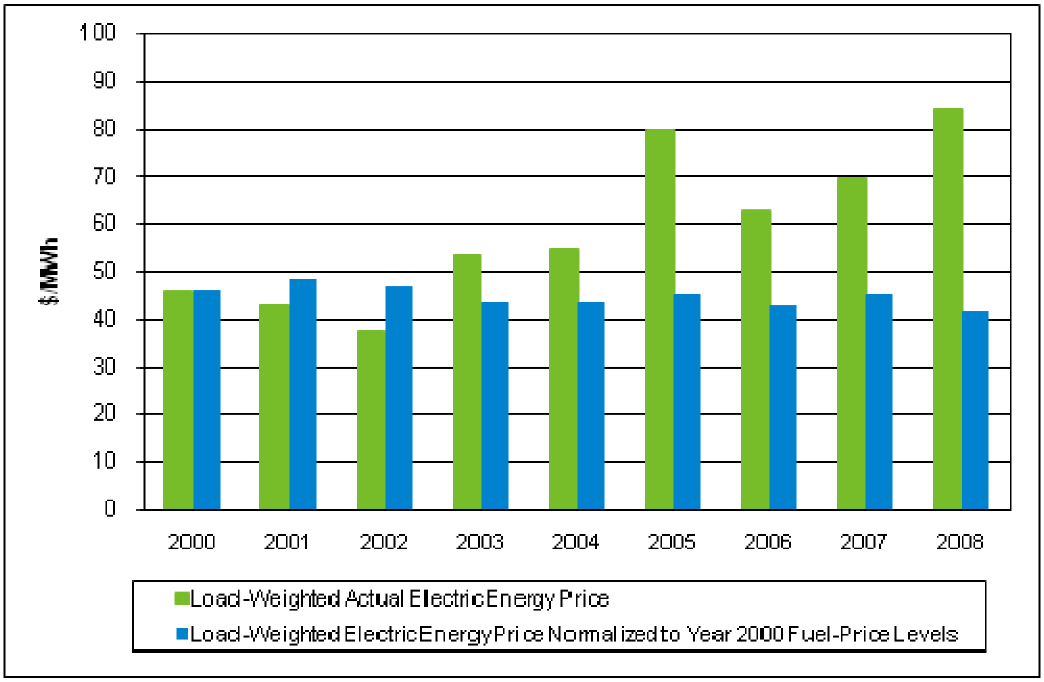

Figure 1-3: Actual and fuel-adjusted average real-time electric energy prices, 2000 to 2008.

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

Unlike the average annual price of electric energy, which rose 21% from the 2007 price, the fuel-adjusted price in 2008, $41/MWh, was 8% lower than the price in 2007.[15] The decline of the fuel-adjusted price from 2007 to 2008 is attributable to two factors: the decrease in energy consumption and an increase in hydroelectric generation, which rose by 19% in 2008. Both factors result in more efficient, lower-cost resources setting the price. Lower loads mean that more efficient resources will satisfy demand. Since hydroelectric energy in New England generally is run-of-river with limited storage, increased hydroelectric energy is offered into the market at the bottom of the supply curve, also increasing the efficiency of the resources that serve load. This hypothesis is supported by an analysis, described in Section 3.3.2, which estimates that the reduction in energy consumption and increased run-of-river and storage hydroelectric output decreased 2008 energy prices by about $5/MWh, or 7%.

1.1.5 2008 Fuel-Price Volatility

The electricity markets were faced with extremely volatile fuel prices during 2008. In early 2008, fuel prices continued an increase that began in late 2007, peaking in summer 2008. By the end of the year, prices fell back to 2007 levels or below. During the week of July 4, 2008, the average price of imported crude oil was $142.52/barrel.[16] This price declined to $32.98/barrel in the last week of 2008.

[15] The average annual load-weighted electric energy price shown in this analysis is a system load-weighted average of Hub prices. This formulation of annual price is used to provide consistency with the methodology used to estimate the fuel-adjusted price, which adjusts the Hub price by the price of the type of fuel used to power the marginal generator.

[16] Energy Information Administration, "Weekly Cushing, Oklahoma (OK), West Texas Intermediate (WTI) Spot Price, Free on Board (FOB), in $/barrel" (Washington, DC: U.S. DOE, March 4, 2009); http://tonto.eia.doe.gov/dnav/pet/hist/rwtcW.htm.

Despite this drop, average fuel prices in 2008 were the highest since the opening of electricity markets in New England in 1999.

Not only were fuel-price levels volatile, but the price of natural gas relative to No. 6 oil changed. In early 2007, No. 6 oil was slightly less expensive than natural gas. It became more expensive than natural gas in spring 2007 and remained so until late 2008, when its price fell below the price of natural gas. The relationship between No. 6 oil and natural gas prices is important in New England's wholesale electricity markets for two reasons. First, at lower No. 6 oil prices, efficient oil generators may displace less-efficient natural gas generators, lowering electricity prices. Second, if oil units needed for reliability are frequently out of merit at higher oil prices, lower oil prices mean lower out-of-market payments for reliability.

Figure 1-4 shows the average monthly fuel prices for 2007 and 2008 for natural gas, No. 6 oil (1% sulfur), and No. 2 fuel oil. The figure illustrates the spike in prices in early summer 2008 and the decline in prices beginning in August. Figure 1-4 also shows the cost of No. 6 oil dropping below the cost of natural gas in November 2008.

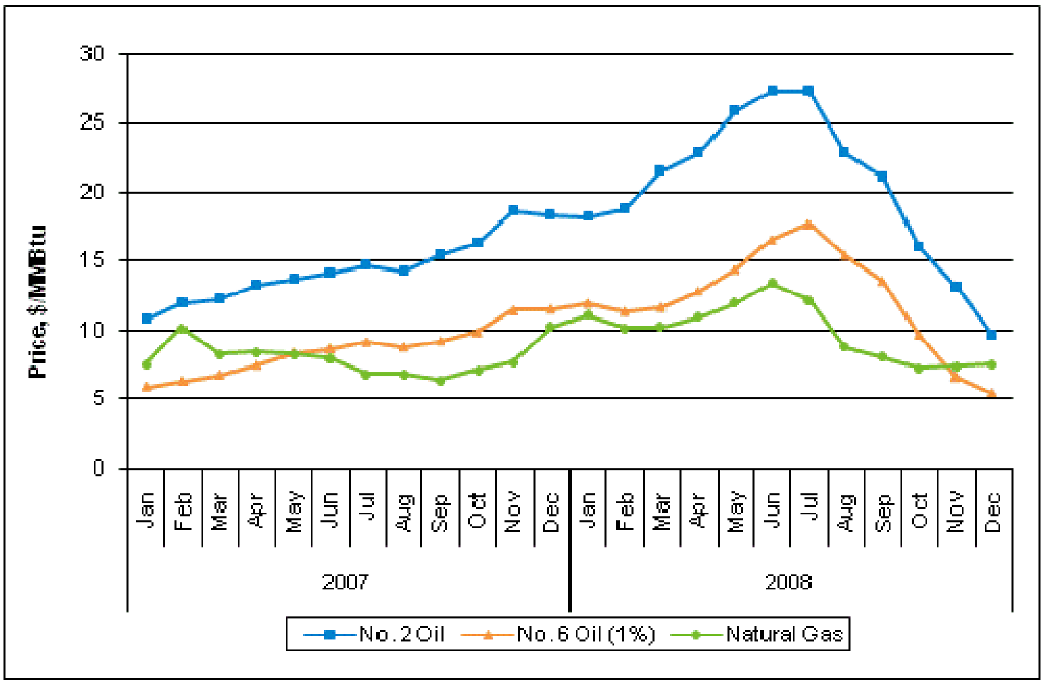

Figure 1-4: Monthly fuel prices, 2007 to 2008.

Sources: Natural gas price information provided by ICE. Oil prices provided by Argus Media.

1.1.6 Zonal Price Separation

Price separation between load zones in 2008 was comparable with 2007 price separation.[17] Connecticut LMPs continued to be higher than those in other zones. LMPs were lowest in Maine. Connecticut prices tend to be higher because of positive marginal congestion costs caused by transmission limits on imports into the state, while Maine prices tend to be lower due to greater line

[17] Price separation between LMPs is the result of different marginal loss and marginal congestion components at the different nodes or zones.

losses and resulting negative marginal costs.[18] The difference between the annual average LMPs for the Connecticut load zone and the Hub was $4.33/MWh in the Day-Ahead Energy Market and $2.78/MWh in real time. The difference between the annual average LMP for the Maine load zone and the Hub was negative $4.45/MWh in the Day-Ahead Energy Market and negative $5.20/MWh in the Real-Time Energy Market. In 2008, total marginal congestion cost was $121 million, and total marginal loss charge was $98 million. In 2007, the total marginal congestion cost was $112 million, and the cost of marginal losses was $94.5 million.

1.1.7 Demand Resources

Demand-resource participation in the New England wholesale electricity markets has increased significantly in recent years. Before the FCM transition period, which began in December 2006, the prices in the capacity market were very low. With the initiation of FCM transition payments, enrollment increased by 138% in 2007. In 2008, demand-response enrollment increased an additional 28%.[19] Figure 1-5 shows the quarterly enrollment of demand resources.

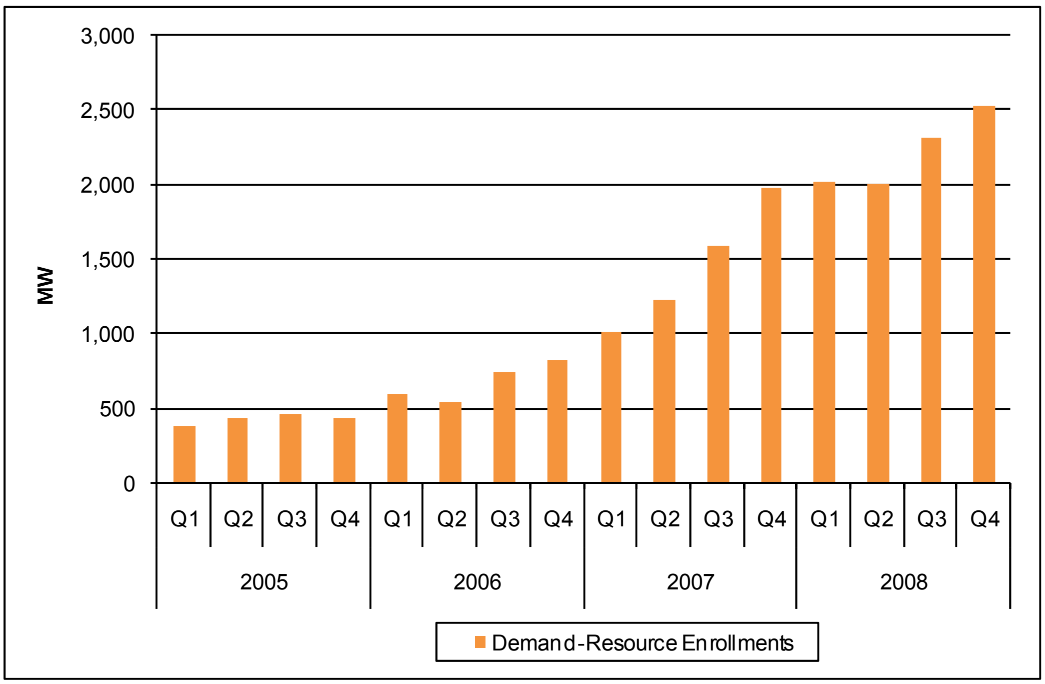

Figure 1-5: Quarterly demand-resource enrollments, 2005 to 2008.

1.1.8 Installed Generating Capacity

The total 2008 generation claimed for capability is 31,088 MW, up 191 MW from the 2007 level of 30,897 MW. These values represent actual conditions as of the summer peaks. The 191 MW increase

[18] *Line losses* occur during the physical process of transmitting electric energy, which produces heat and results in less power being withdrawn from the system than was injected. Line losses and their associated marginal costs are inherent to transmission lines and other grid infrastructure.

[19] *Demand response* in wholesale electricity markets occurs when market participants reduce their consumption of electric energy from the network in exchange for compensation based on wholesale market prices. The ISO operates three types of demand-response programs: those activated by price, those activated for reliability, and those that reduce on-peak consumption.

is the result of new generation, existing generation reratings, or "behind-the-meter" generation.[20] By comparison, 44 MW of new generation were added to the system in 2007, no new generation resources were added in 2006, and 92 MW of new generation were added in 2005.

1.1.9 Competitiveness of the Electric Energy Markets

A competitive market requires a market structure in which many competitors participate in the market and none of the competitors is large enough to affect price. Because the New England energy markets have many competitors and no single competitor is large enough to affect the market price, the regionwide market structure provides the foundation for a competitive market. Additionally, mitigation measures provide protection when and where inadequate transmission or peak load levels create the possibility of noncompetitive behavior.

The INTMMU examined the region's market structure and market results in detail. The examination of market results shows that electric energy prices reflect the costs to suppliers of producing 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.

To assess the competitiveness of the electric energy markets, the INTMMU examined two types of measures of market competitiveness: structural measures of competitiveness, which analyze the ownership shares of generation resources in the New England markets, and price-based measures, which compare wholesale market prices to the estimated cost of providing electric energy. The structural measures used were the Herfindahl-Hirschman Index (HHI) and the Residual Supply Index (RSI).[21] The price-based measure used was the competitive benchmark.[22] These measures are described in more detail in Section 3.1.1.

The HHI of about 600 for the entire New England region for 2008 indicates the market is not concentrated at the systemwide level. This is well below the 1,000 level the U.S. Department of Justice (DOJ) uses as the maximum HHI for an unconcentrated market.[23]

The RSI results for all of 2008 show that output from the largest supplier was required a total of 51 hours in June and July. However, a review of the RSIs for the local reserve zones, Connecticut (CT), Southwest Connecticut (SWCT), and Northeast Massachusetts/Boston (NEMA/Boston), during June and July 2008 indicated that these zones had pivotal suppliers during most days within these

[20] *Behind-the-meter* generation is connected to the power grid at an electrical location that is on the load side of the metering facility that connects to the transmission system controlled by the ISO. Output from a behind-the-meter generator reduces the amount of electric energy that needs to be withdrawn from the ISO-controlled network.

[21] The *Herfindahl-Hirschman Index* (HHI) is a measure of market concentration based on generating capacity. The systemwide *Residual Supply Index* (RSI) measures whether the load in a given hour in megawatt-hours (MWh) 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.

[22] A price mark-up model, or *competitive benchmark price model*, models and compares prices based on competitive offers with prices based on actual offers.

[23] The Department of Justice defines markets with an HHI below 1,000 points to be unconcentrated, an HHI between 1,000 and 1,800 points to be moderately concentrated, and an HHI above 1,800 points to be highly concentrated. (U.S. Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines*, April 8, 1997; http://www.usdoj.gov/atr/public/guidelines/horiz_book/15.html).

months.[24] This indicates a concentrated local market in which suppliers may have the ability to exercise market power. This structural feature of the New England markets indicates that the mitigation measures for constrained areas are vital to prevent suppliers with market power from using it to raise prices. Section 3.1.3 contains more details on these RSI calculations.

The results of the competitive benchmark model are shown in Table 1-2 and are consistent with the results of previous years. The results show that modeled electric energy prices using participants' actual supply offers (offer-intercept prices) did not differ significantly from modeled prices using estimated short-run variable costs as supply offers (competitive benchmark prices). Thus, the model results support the conclusion that market prices are consistent with what prices would have been had resource owners offered at their short-run variable costs. The lack of a significant difference between modeled prices using actual offers and modeled prices using short-run costs is strong evidence that the markets are competitive.

Table 1-2
ISO Model Market Price Measures

Price Measure	2008 Price ($/MWh)	Quantity-Weighted Lerner Index (%)(a)					
		2003	2004	2005	2006	2007	2008
Competitive benchmark price	$77.86						
Aggregate offer-intercept price	$76.94	−4	−6	1	1	2	−1

(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].

The competitive benchmark model is a supply curve model that does not fully account for unit outages, commitment costs, resource flexibility, or transmission constraints. These simplifications result in model prices that consistently are lower than actual prices. While the modeled prices are in the range of $77/MWh, the actual system load-weighted average Hub price for 2008 was $83.91/MWh.[25] The INTMMU plans to review the performance of the benchmark model and investigate replacing the current benchmark model with an approach that uses a production-costing dispatch model, which will be reported in the *2009 Annual Markets Report*.

Based on a competitive regionwide market structure and electric energy prices tracking changes in natural gas prices, the INTMMU finds that the electric energy market prices in 2008 were consistent with those of a competitive market.

1.2 Reliability and Operations

The need to operate generators out of merit to maintain system reliability and to compensate them with Net Commitment-Period Compensation (NCPC) has been a longstanding issue in New

[24] *Reserve zones* are geographic areas that have specific reserve requirements necessary for the reliable operation of the system. The ISO has four reserve zones: NEMA/Boston, Connecticut, Southwest Connecticut, and the rest of the system (Rest-of-System; ROS).

[25] The system load-weighted average Hub price is used because it provides the closest conceptual match to the prices calculated by the benchmark model.

England.[26] The level of out-of-merit generation is lower than in past years. In some regions, the completion of transmission projects has reduced the need to run resources out of merit to maintain reliability during transmission construction. In other areas, transmission improvements have eliminated or significantly reduced the need for out-of-merit generation to maintain reliability. This section discusses trends in the amount and cost of out-of-merit generation. While out-of-merit generation decreased by 35% from 2007 to 2008, costs in 2008 increased slightly over 2007 because of higher fuel costs.

Table 1-3 shows the out-of-merit generation by year and commitment category. All categories of out-of-merit generation decreased in 2008 compared with 2007. Out-of-merit generation as a percentage of total energy dropped below 2%, to 1.9%, for the first time since 2003.

Table 1-3
Generation from Out-of-Merit
Reliability Commitments Paid NCPC, by Type, GWh

Year	Second Contingency	Voltage	Distribution	First Contingency	Total	% of Total Energy
2003	598.59	322.16	44.68	743.94	1,709.37	1.6
2004	454.01	1,183.82	127.50	1,661.85	3,427.18	2.6
2005	1,785.35	977.40	142.39	1,266.51	4,171.64	3.1
2006	2,282.82	327.77	177.36	436.95	3,224.89	2.4
2007	2,704.53	645.06	11.41	528.16	3,889.16	2.9
2008	1,658.05	427.45	4.65	458.75	2,548.91	1.9

Table 1-4 compares total out-of-merit generation from 2003 to 2008 for several areas. It shows that SEMA accounted for 57% of the out-of-merit generation in 2008 and that most of the remainder was split between Connecticut and NEMA.

[26] *Net Commitment Period Compensation* (NCPC) 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, see *Market Rule 1*, Section III, Appendix F, *Net Commitment-Period Compensation Accounting*; http://www.iso-ne.com/regulatory/tariff/sect_3/.

Table 1-4
Generation from Out-of-Merit
Reliability Commitments Paid NCPC, by Location, GWh

Year	SWCT	Rest of Connecticut	SEMA	NEMA/ Boston	Rest of System	All of New England
2003	231.25	346.84	97.82	679.04	354.43	1,709.37
2004	210.52	224.27	138.32	2,446.90	407.18	3,427.18
2005	328.85	458.59	368.63	2,683.54	332.03	4,171.64
2006	400.89	574.53	1,240.43	545.72	463.33	3,224.89
2007	327.16	423.09	1,543.29	1,129.19	466.42	3,889.16
2008	270.90	101.58	1,440.68	238.17	497.58	2,548.91

Three areas showed significant reductions in out-of-merit generation: Southwest Connecticut, Rest of Connecticut, and NEMA. Connecticut and Southwest Connecticut combined dropped from 750 GWh in 2007 to 372 GWh in 2008. The reductions in both Connecticut regions were attributable to the completed construction of two major transmission lines, which eliminated the need to run resources out of merit to maintain reliability during construction. The large drop in out-of-merit generation in the Boston area was due to transmission improvements into the Boston area, which eliminated the need to run units out of merit for voltage support on a routine basis.

Transmission improvements expected in 2009 are anticipated to significantly reduce the need for out-of-merit generation in SEMA. Continued declines in out-of-merit generation will improve the efficiency of the wholesale electric energy markets by reducing the distortion in energy prices caused by out-of-merit generation.

As shown in Table 1-5, the total cost of out-of-merit generation was slightly higher in 2008 than in 2007. These slightly higher costs are attributable to higher fuel costs in 2008. If the megawatt-hours of out-of-merit generation had remained the same as in 2007, reliability costs could have been much greater.

Table 1-5
Cost of Out-of-Merit Generation, $ in Millions

Payment Type	2007	2008	Difference	% Change
First-contingency reliability payments	29.6	44.4	14.8	50%
Second-contingency reliability payments	169.5	182.5	13.0	8%
Distribution	1.8	1.5	−0.3	−17%
Voltage	46.0	29.4	−16.6	−36%
Total	246.9	257.8	10.9	4%

In 2008, the INTMMU designed changes to the mitigation of NCPC. The changes tighten the current thresholds and, when fully implemented, will reduce revenues in excess of short-run costs paid to resource owners when system operators must rely on output from a resource's more expensive out-of-merit generation because of a lack of competition. The changes went through the stakeholder process in 2008 and are expected to be implemented in 2009.

1.3 Forward Capacity Market and Transition Period

This section summarizes the 2008 activities related to the Forward Capacity Market, including the FCM transition period payments, proposed and accepted revisions to FCM rules, and the results and competitiveness of the two FCA auctions that were held during 2008. The ISO has been making progress in refining the FCM market rules. Additionally, the INTMMU has found that the first two FCAs were competitive.

1.3.1 FCM Transition Period

As defined in the FCM Settlement Agreement, FCM transition payments replaced the Installed Capacity Market in December 2006 and will continue until the 2010/2011 capacity commitment period when the FCM payments based on the auction results will begin.[27] FCM transition payment rates were $3.05/kW-month through May 2008 and then increased to $3.75/kW-month in June 2008, as laid out by the FCM settlement. During 2008, FCM transition payments to qualifying capacity resources totaled $1.5 billion compared with $1.3 billion in 2007.

In 2008, pursuant to a May FERC order, the ISO and the INTMMU developed changes to the rules determining how capacity imports must offer into the energy market.[28] The proposal will require priced capacity imports to offer energy at a competitive price, replacing the current rules that permit capacity imports to offer up to the $1,000/MWh price cap. A second change revises the penalty paid by a capacity importer when the ISO requests electric energy from an energy transaction that is supporting a capacity import, and the energy does not flow in real time. The proposal replaces the existing "failure-to-deliver" penalty structure with one that bases the penalty on the percentage of hours during which electric energy is requested but not delivered from a capacity contract. The proposed rule was filed with FERC in March 2009 and was approved for implementation on July 1, 2009.[29]

1.3.2 Forward Capacity Auctions

The second FCA took place on December 8–10, 2008. The auction cleared at the minimum price of $3.60/kW-month with an excess supply of 4,755 MW above the Installed Capacity Requirement of 32,528 MW. The auction included two capacity zones: Maine (as a potentially export-constrained zone) and the Rest-of-Pool capacity zone.[30] However, no price separation occurred during the second FCA; therefore, the second FCA resulted in a single capacity zone.

[27] A *capacity commitment period*, also known as a *capability year*, runs from June 1 through May 31 of the following year.

[28] *Order Approving Tariff Changes*, FERC Docket No. ER08-697-000 (issued May 20, 2008).

[29] The March 20 filing has engendered ongoing litigation. Errors in that filing and associated concerns raised by the litigants have led the ISO board to secure an external review of the causes of the errors and related INTMMU processes and controls.

[30] A *capacity zone* is an area that has a locational capacity need, either a *local sourcing requirement* (LSR), which is an import-constrained area with insufficient local capacity, or a *maximum capacity limit* (MCL), which is an export-constrained area that has a surplus of capacity. These limits and requirements are based on network models using lines that will be in service no later than the first day of the relevant capacity commitment period.

New resources accounted for 3,134 MW of the total resources that cleared in the auction, of which 448 MW were demand resources, 1,157 MW were new generation resources, and 1,529 MW were new import capacity. Of the 1,157 MW of new generation capacity, 1,008 MW were associated with resources procured in two requests for proposals (RFPs) by the State of Connecticut. This new entry was counterbalanced by 890 MW of existing resources that *delisted* (i.e., exited the capacity market) during the auction. Demand resources accounted for 489 MW of the existing resource delistings, leaving a total of 2,778 MW of demand resources for the 2011/2012 capacity commitment period.

The ISO reviewed the 890 MW of *delist bids* (i.e., bids for resources to leave the market if prices fall below the bid level) a total of 365 delist bids from resources in all six New England states, to determine whether having these resources exit the auction would adversely affect reliability. None of the delist bids was rejected for reliability reasons. Because all resources in total are paid only the clearing price multiplied by the net ICR (NICR), they are given the option of either accepting a lower price on all of their capacity or reducing their resources in the market by the ratio of the NICR to the total capacity clearing in the auction.[31] For the 2011/2012 capacity commitment period, this prorated price is $3.12/kW-month, based on the NICR of 32,528 MW and the surplus of 4,755 MW.[32]

The INTMMU will publish a report in June 2009 that reviews the performance of the FCM. Further analysis and recommendations will be included in that report.

1.3.3 Compensation for Resources Needed for Reliability

The ISO filed and FERC accepted changes to the compensation of resources that are interested in leaving the FCM via delist bids but are needed for reliability reasons.[33] The changes are consistent with and support the FCM market design and are based on two principles. First, the changes provide for the payment of resources that want to leave the capacity market for one year based on their going-forward costs rather than their cost-of-service rates. Second, the changes provide the opportunity for resource owners to receive cost-of-service rates for resources that seek to leave the FCM permanently, either through the submission of a permanent delist bid or a nonprice retirement request.

These changes are important to the market because they restrict the ability of resources to obtain full cost-of-service agreements outside the FCM unless the resource wishes to retire or permanently exit the market. This will help the FCM meet one of its objectives, reducing Reliability Agreements.

1.3.4 The FCM and the Generation Interconnection Queue

The ISO filed and FERC accepted changes to the ISO *Open Access Transmission Tariff* (OATT) to integrate the FCM and the generator interconnection process to achieve greater market efficiency through the allocation of interconnection rights and responsibilities.[34] First, the changes create two

[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). 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.

[32] A total of 1,695 MW of self-supplied resources are excluded from the proration.

[33] *Tariff Revisions to Provide Additional Flexibility for Retirement of Resources in the Second Forward Capacity Auction*, FERC Docket ER08-1224-000 (August 1, 2008).

[34] (1) The ISO operates under the FERC tariff, *ISO New England Transmission, Markets, and Services Tariff* (2005). Section II of this tariff is the *Open Access Transmission Tariff* (OATT), and Section IV of this tariff is the *Self-Funding and Capital Funding Tariff*. These documents are available at http://www.iso-ne.com/regulatory/tariff/index.html. (2) *Order*

levels of interconnection service—capacity and energy-only—to offer interconnection customers the option of interconnecting based on their ability to participate in the markets. Second, the changes address the relationship between the FCM and the interconnection queue process by incorporating a "first-cleared-first-served" construct to allocate limited interconnection capacity rights to those generating resources with a demonstrated ability and commitment to provide capacity to meet the New England Installed Capacity Requirement.[35] Last, these amendments provide for a more efficient queuing process by assuring that only projects that remain viable remain in the interconnection queue.

1.3.5 Competitiveness of the Forward Capacity Market

In FERC testimony, the INTMMU reported its finding that the results of both FCA #1 and FCA #2 were competitive.[36] This finding was based on an effective auction design, rigorous qualification requirements, an abundance of initial offers, and the absence of potential anticompetitive behavior observed during the conduct of the auction.

1.4 Forward Reserve Market

The Forward Reserve Market (FRM) and real-time reserve pricing help to ensure that the region will have the operating reserves needed for real-time reliability. Prices have been dropping in the forward-reserve auctions, except in Connecticut, which does not yet have sufficient off-line reserve capacity to meet its needs.

1.4.1 Locational Forward-Reserve Auction Results

The results of the locational forward-reserve auctions are shown in Table 1-6. Prices for New England systemwide 10-minute nonspinning reserve (TMNSR) in both the summer and winter auctions declined from 2007 to 2008.[37] Prices in the Connecticut and Southwest Connecticut reserve zones remained at the $14.00/kW-month cap because of insufficient capacity in those regions to meet the reliability criterion. Prices for 30-minute operating reserve (TMOR) in NEMA dropped in winter 2008 because the completion of transmission upgrades into the Boston area resulted in a decrease in the requirement. Prices for systemwide TMOR have fluctuated because the systemwide TMOR requirement can be met by higher-quality reserve products and TMOR that clears in other locations. Section 5.1.1.3 contains more details.

Accepting Tariff Revisions, FERC Docket Nos. ER04-432-006, ER04-433-006, ER07-546-013, ER07-547-003 and ER09-237-000, January 30, 2009.

[35] The ISO's Generator Interconnection Queue tracks the resources that have requested interconnection studies. Additional information on the projects in the queue is available online at http://www.iso-ne.com/genrtion_resrcs/nwgen_inter/index.html.

[36] FCA#1: ISO New England Inc., Docket No. ER08-633-000. *Forward Capacity Auction Results Filing* (March 3, 2008); http://www.iso-ne.com/regulatory/ferc/filings/2008/mar/er08-633-000_03-03-08_fca_results_filing.pdf. FCA #2: ISO New England Inc., Docket No. ER09-467-000. *Forward Capacity Auction Results Filing* (December 23, 2008); http://www.iso-ne.com/regulatory/ferc/filings/2008/dec/er09-467-000_12-23-08_fca_results.pdf.

[37] Ten-minute nonspinning reserve (TMNSR) is off-line operating reserve generation that can be electrically synchronized to the system and reach rated capability within 10 minutes in response to a contingency. Ten-minute spinning reserve (TMSR) is on-line reserve electrically synchronized to the system that can increase output by a specified amount and at rated capability that can respond to a contingency within 10 minutes. Thirty-minute operating reserve (TMOR) is on-line or off-line operating reserve generation that can increase output within 30 minutes or be electrically synchronized to the system and reach rated capability within 30 minutes in response to a contingency. The status of a particular resource as a "claim-10 or claim-30" resource depends on the existing operating state of the resource.

Table 1-6
Results of Locational Forward-Reserve Auctions, $/kW-Month

Reserve Zone	Reserve Category	Summer 2007	Summer 2008	Winter 2007/2008	Winter 2008/2009
Systemwide	TMNSR	$10.80	$8.88	$9.05	$6.74
Systemwide	TMOR	$3.55	$6.50	$0	$4.99
SWCT	TMOR	$14.00	$14.00	$14.00	$14.00
CT	TMOR	$14.00	$14.00	$14.00	$14.00
NEMA/Boston	TMOR	$14.00	$14.00	$8.50	$5.55

A total of 800 MW of TMNSR was purchased systemwide in each auction. There are no local requirements for TMNSR.

The Connecticut local reserve zone had a requirement of about 1,300 MW in each of the two auctions. Of this amount, about 600 MW must be in Southwest Connecticut. NEMA requirements were 300 MW in the summer 2008 auction and 135 MW in the winter auction. The 165 MW drop was enough to decrease the price from the cap to $5.55/kW-month. Locational FRM payments are made net of capacity payments, which were $3.75/kW-month beginning June 1, 2008. Thus, the net payment for the most recent NEMA auction is $1.80/kW-month.

1.4.2 Auction Observations and Recommendations

Table 1-7 shows the total available capacity that is capable of providing either 10- or 30-minute off-line reserve capability, the amount of such capacity participating in the auction, and the auction requirements for the past five auctions. The INTMMU will evaluate why auction participation was only in the range of 50% of the total capacity eligible to participate in the auctions and if this has implications for the competitiveness of the auctions.

Table 1-7
Total Capacity Able to Provide Off-Line Reserves, System Reserve Requirements, and Capacity Offered into the Locational FRM, MW

	System TMNSR			System TMOR		
Auction	**Required MW**	**Offered MW**	**Total 10-Minute Capacity**	**Required MW**	**Offered MW**	**Total 30-Minute Capacity**
Summer 2007	700	1,010	3,550	700	1,403	3,966
Summer 2008	800	1,338	2,741	650	1,282	3,334
Winter 2006/2007	700	1,098	4,595	700	1,561	5,215
Winter 2007/2008	850	1,237	2,735	700	1,793	3,249
Winter 2008/2009	800	1,474	2,870	750	1,566	3,450

As indicated in the ISO's *2007 Annual Markets Report*, the INTMMU recommends two technical improvements to the forward-reserve auction design. First, under the existing rules, the Rest-of-

System TMOR requirement is increased by an "R-factor" of 33% (1.33) to account for resource outages and real-time failures to start. Performance data, described in Section 5.1.2, show significantly improved performance for these resources. As a result of this improvement, the INTMMU recommends reducing the R-factor. This will reduce the total amount that must be purchased in the auction and should lower the clearing price.[38] The second improvement concerns the process for setting the price level at which resources designated for the FRM are required to offer their energy. This process should be reviewed to determine whether it is still functioning as designed.[39]

Possible changes to encourage new investment and increased participation include switching to one annual auction or more closely integrating the forward-reserve auctions with the FCM. Either would be a significant change and should be implemented only after careful review and analysis.

1.4.3 Competitiveness of the Reserve Market

Structural analysis of the FRM auctions indicates a moderate to high concentration of New England-wide reserve products, based on Herfindahl-Hirschman Indices ranging from 1,200 to 2,300. Prices in the locational Forward Reserve Market have been decreasing for regionwide products, indicating that competition may be lowering prices in the regionwide FRM. However, the subregional reserve zones are not competitive. Connecticut has insufficient reserve capacity to meet the zonal reserve requirements. Consequently, the Connecticut and SWCT reserve zones have cleared at the price cap of $14.00/kW-month in each reserve auction. In the NEMA reserve zone, the HHI for reserve capacity was about 2,500 in summer and 2,200 in winter, which inidcates a highly concentrated market. The summer 2008 auction cleared at the $14.00/kW-month cap, but recent transmission improvements have lowered the reserve requirement, and the latest winter auction cleared at $5.50/kW-month, which is consistent with competitive outcomes.

1.5 Regulation Market

The Regulation Market provides moment-to-moment balancing services to assure that generation and load are kept balanced in real time. This market functioned well in 2008. During the year, the ISO met the North American Electric Reliability Corporation (NERC) reliability standards for this area and reduced the capacity on regulation.[40]

Figure 1-6 shows monthly Regulation Market costs and requirements for 2007 and 2008. Average regulation requirements have dropped from 181 MW in 2002 to 120 MW in 2008. More recently the monthly average requirements dropped from 129 MW in 2007 to 120 MW in 2008. Total costs of the Regulation Market rose from $43.8 million in 2007 to $50.5 million in 2008 (a 15.3% increase). The regulation cost increase was caused by two main factors. First, the increase in natural gas prices raised the opportunity cost of providing regulation. Second, natural gas units that were providing lower-cost regulation during the on-peak hours were decommitted in off-peak hours, which led to the use of more expensive regulation sources.

[38] For this analysis, all claim-10 and claim-30 resources were evaluated.

[39] To remain eligible for FRM payments, resources designated as forward-reserve resources for the day must offer their electric energy at a price greater than or equal to the FRM threshold price.

[40] NERC reliability standards can be accessed at http://www.nerc.com/page.php?cid=2|20 (Princeton, NJ: NERC, 2008).

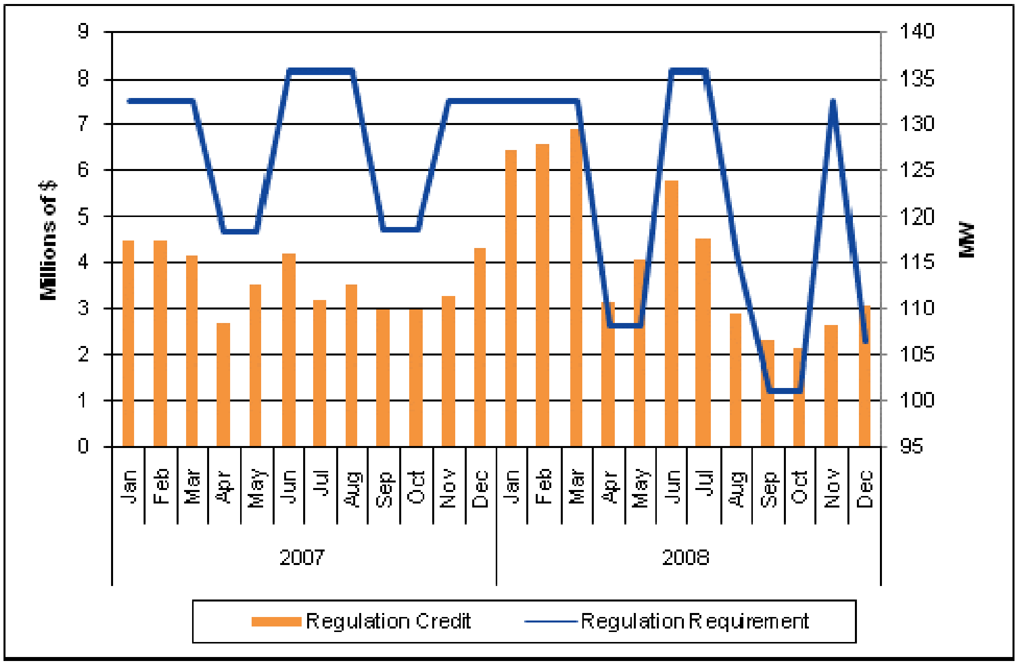

Figure 1-6: Monthly Regulation Market costs and requirements for 2007 and 2008.

Structural analysis of the Regulation Market shows that this market has an HHI of about 900, based on the monthly average of capacity capable of providing regulation and monthly RSIs in excess of 1,000 during all months. These structural indices for the Regulation Market indicate that a high level of competition exists for providing regulation services. The INTMMU review of prices in the Regulation Market in 2008, described further in Section 6.4, shows that regulation prices are consistent with the opportunity cost of providing regulation.

1.6 Mitigation and Market Reform Activities

This section describes mitigation actions during the year and reforms to the Day-Ahead Load-Response Program (DALRP).

1.6.1 Mitigation Actions

During 2008, the ISO exercised its market-mitigation authority five times as part of its responsibility to monitor the markets and ensure efficient and competitive market results. One mitigation event was for economic withholding in the Day-Ahead Energy Market, two mitigation events were for economic withholding in the Real-Time Energy Market, and the remaining two mitigation events were for economic withholding for NCPC. Mitigation was imposed when the participant did not adequately explain a supply offer that exceeded conduct and market-impact thresholds. As a result of the mitigation, a supply offer representing the unit's marginal costs was substituted for the generating resource's offer.

1.6.2 Market Reforms

On February 5, 2008, the ISO filed changes to the Day-Ahead Load-Response Program to change the program's trigger price from a fixed cost of $50.00/MWh to prices based on a natural gas unit with a

12,920 Btu/MWh heat rate indexed to the daily price of natural gas.[41] These changes restored the program design to its original purpose of encouraging load reductions during times of high prices, which had been lost when rising fuel prices made the $50.00/MWh price a low price level for electricity. The fixed program-trigger price also facilitated strategic bidding by participants that overstated their baseline energy use, leading to overstated interruptions and payments. After the changes were implemented in February 2008, program interruptions fell from 43,606 MWh in January 2008 to an average of 2,052 MWh per month for the rest of the year. This is illustrated in Figure 1-7 showing the gigawatt-hours of interruption from the DALRP over time and the minimum offer price, with the change from a fixed price of $50/MWh to a variable price based on the daily natural gas price. This indicates that the changes have restored the program's original purpose of reducing load only during periods of high prices.

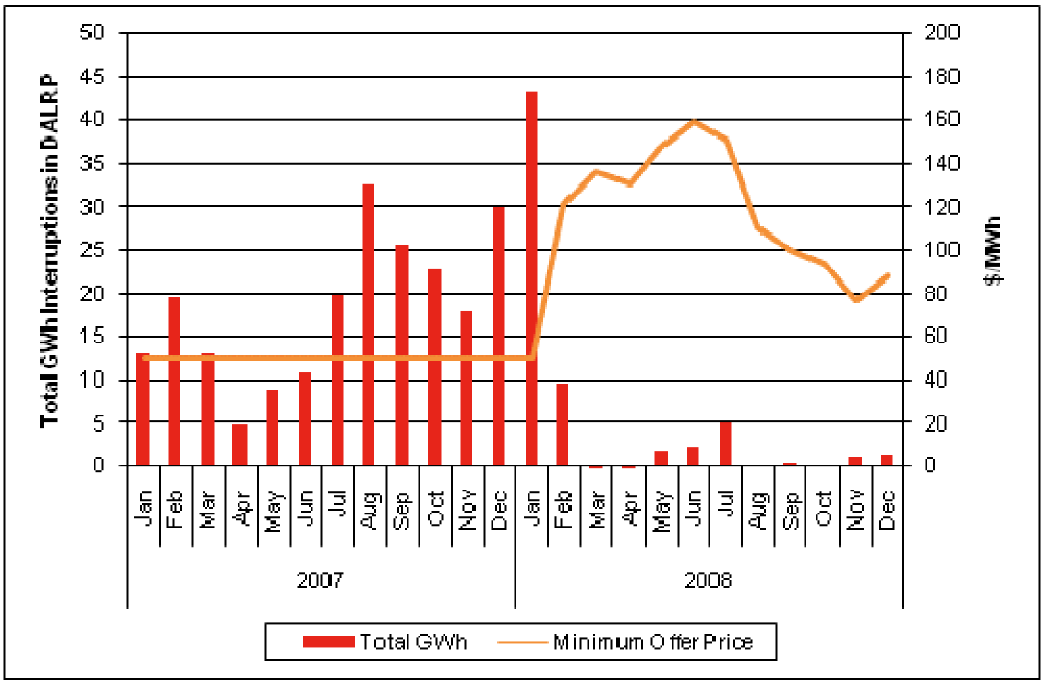

Figure 1-7: Total interruptions in the DALRP per month, 2007 to 2008.

[41] (1) FERC Docket ER08-538, *Filing of Changes to Day-Ahead Load-Response Program*, (February 5, 2008). (2) The *trigger price* is the minimum price at which market participants can offer load reductions into the day-ahead market. The $50.00 trigger price was set in 2002 when natural gas prices were in the $2.00 to $3.00 range and $50.00/MWh was a high energy price. (3) A generator's *heat rate*, traditionally reported in Btu/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.

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

ISO New England is responsible for overseeing and administering New England's interrelated suite of competitive wholesale markets. These markets work together to ensure the constant availability of electricity for the region's 6.5 million households and businesses and 14 million people. In 2008, more than 400 market participants completed approximately $12 billion of wholesale electricity transactions to generate, buy, sell, and transport wholesale electricity. Other products traded in New England's wholesale markets ensure proper system frequency and voltage, sufficient future capacity and future and real-time reserve capacity, and system start-up capability after a systemwide blackout. Stakeholders also have the opportunity to hedge against the costs associated with transmission congestion. 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 instantaneous demand for electricity.[42]
- **Forward Capacity Market (FCM)**—ensures that installed capacity, which includes demand resources, is sufficient 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 resources that the ISO instructs to increase or decrease output moment by moment to balance the variations in demand and system frequency, which always 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.[43]
  - **Real-time reserve pricing**—is the ISO's mechanism to implement *scarcity pricing*, which compensates on-line generators above the marginal cost of electric energy for the increased value of their energy when the system or portions of the system are

[42] *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.

[43] *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) of a system is lost, which has the largest impact on system reliability. A *second contingency* (N-1-1) is the loss of the facility that would have the largest impact on the system after the first facility is lost.

short of reserves. It also provides efficient price signals to generators when redispatch is needed to provide additional reserves to meet requirements.

- **Voltage support**—allows system operators to maintain transmission voltages within acceptable limits.

The ISO relies on two independent market monitoring units—one internal and one external—to quickly detect and mitigate anticompetitive market behavior or outcomes. The internal market monitor is referred to as the Internal Market Monitoring Unit (INTMMU), and the external market monitor is referred to as the Independent Market Monitoring Unit (IMMU). 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. 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 production and consumption 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., operating at a determined output level 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 to ensure that customers receive the electric energy they demand. 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) for the amount of load or generation in megawatt-hours 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.

2.1.1 Locational Marginal Prices and Pricing Locations

Locational marginal pricing is a way for wholesale electric energy prices to efficiently reflect the variations in supply, demand, and transmission system limitations wherever electric energy enters or exits the high-voltage physical transmission system controlled by the ISO. In New England, wholesale electricity prices are set at 900 pricing points (i.e., *pnodes*) on the bulk power grid. LMPs differ among these locations as a result of each location's marginal cost of congestion and marginal cost of line losses. The congestion cost component of an LMP arises because of the need to dispatch individual generators to provide more or less energy because of transmission system constraints that limit the flow of economic power. Line losses occur during the physical process of transmitting electric energy, which produces heat and results in less power being withdrawn from the system than was injected. Line losses and their associated marginal costs are inherent to transmission lines and other grid infrastructure as electric energy flows from generators to loads. As with the marginal cost of congestion, the marginal cost of losses has an impact on the amount of generation that needs to be dispatched. The ISO operates the system to minimize total system costs.

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 electric energy available to serve that load, and energy from that generator would be able to flow to any node over the transmission 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.[44] 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 that has a price intended to represent an uncongested price for electric energy; facilitate trading; and enhance transparency and liquidity in the marketplace. In New England, 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.[45] 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 do not have enough local resources and transmission-import capability to serve local demand reliably. *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. 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).

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, supplier operating characteristics, and the frequency and location of transmission constraints. 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 based on supply offers, external transaction offers, virtual (financial) offers and bids, and day-ahead demand bids. The market-clearing process for the Real-Time Energy Market is based on supply offers, real-time load, and offers and bids to sell or buy energy over the external interfaces.

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[44] 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. Balancing authority areas were formerly referred to as *control areas*. Further information is available in the NERC glossary at http://www.nerc.com/docs/standards/rs/Glossary_12Feb08.pdf (accessed December 8, 2008).

[45] *Market Rule 1* contains provisions that allow participants that meet certain requirements to request nodal pricing for load. However, the number of participants that has exercised this option and the quantity of load these participants serve is very small relative to the zonal load levels.

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 cost of operating based on hours of operation rather than the megawatt level of output. Additionally, market participants have incentives to submit incremental energy offers that reflect their units' marginal costs of production and start-up and no-load offers, which reflect the resources' actual costs.

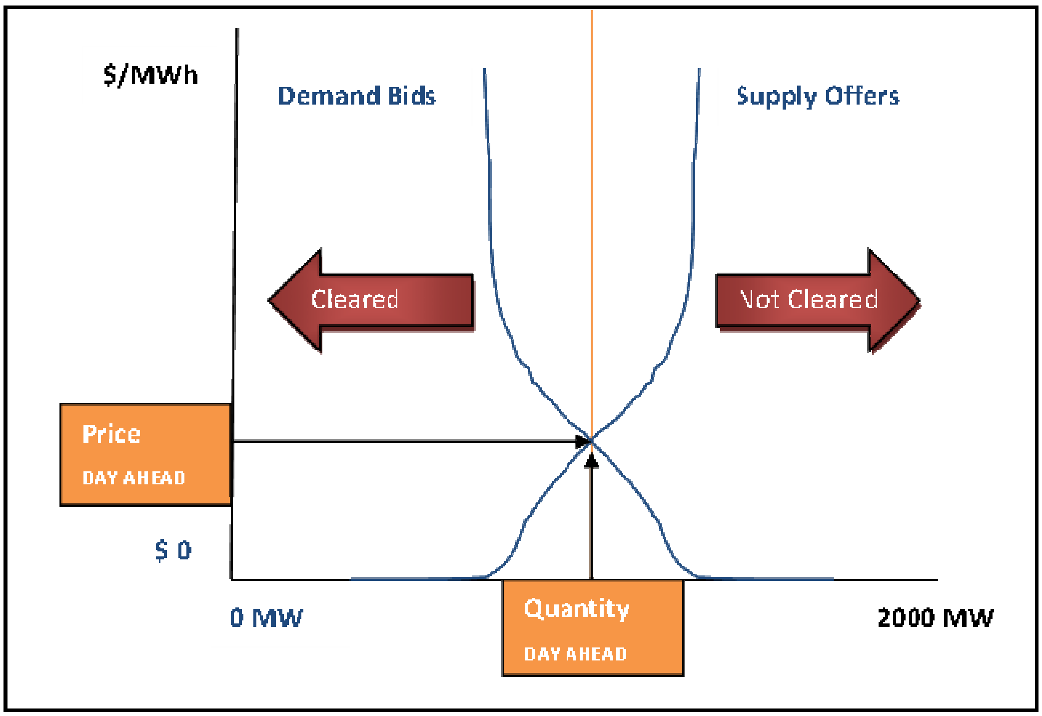

Figure 2-1: Intersection of supply and demand curves indicating the clearing price.

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. Participants also may offer *virtual supply*. Virtual trading enables market participants that are not generator owners or load-serving entities 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. Because load is priced at the zone and demand bids are only zonal, the demand bids are well suited to hedge RTLOs. Virtual demand bids can be used to arbitrage expected differences between day-ahead and real-time prices at a node. They also may hedge a particular load, such as a factory that has elected to receive the nodal LMP.

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.

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 accounting for transmission system limits, the need for reserves, 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 needed and available supply 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.[46] 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 all levels of cleared, anticipated, and 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 and Section 5 for more on reserves).[47]

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 that have high demand relative to economic supply, more expensive generation may need to be called on, which results in higher LMPs in that area and lower

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[46] 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.

[47] *Fast-start resources* are resources that are able to respond quickly to system contingencies that remove equipment from service.

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—less expensive generation can be dispatched. These areas can experience lower LMPs compared with unconstrained areas that can more readily export excess supply. Financially, the Real-Time Energy Market is settled 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

In 2002, the FERC charged the ISO with revising the Installed Capacity Market to better address resource adequacy and local reliability issues in New England.[48] This directive culminated in a Settlement Agreement that was negotiated before a FERC settlement judge and involved numerous stakeholders, including state officials, utility companies, generating companies, consumer representatives, regulators, and other market participants.[49] On June 16, 2006, FERC approved the agreement, which provided a framework for drafting the Forward Capacity Market rules. FERC approved the FCM rules on April 16, 2007.

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. 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 or 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 the December 2006, when the FCM Settlement Agreement terminated the Installed Capacity Market, and June 1, 2010, when the winners of the first FCA must deliver capacity, is referred to as the FCM transition period. 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 that are 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).[50] The net Installed Capacity Requirement (NICR)

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[48] *Order Accepting in Part and Modifying in Part Standard Market Design Filing and Dismissing Compliance Filing* (SMD Order), FERC Docket Nos. ER02-2330-000 and EL00-62-039 (September 20, 2002), p. 37.

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

[50] 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 *2008 Regional System*

values are the ICRs for the region, minus the tie-reliability benefits associated with the Hydro-Québec Phase I/II Interface (termed HQICCs).[51] Other key FCM inputs include locational capacity needs to ensure that local areas secure ample supplies during the auction for maintaining reliability during the capability period 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.[52]

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). Export-constrained areas, which have a surplus of capacity, are assigned a *maximum capacity limit* (MCL).

Existing FCM resources must serve a period of one capacity commitment period, and new resources may commit to as many as five such periods. 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.[53] These prices are based on the estimated fixed costs for developing capacity resources in the region and the clearing price of previous FCAs. CONEs establish a $/kW-month value of how much it would cost 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 $7.50/kW-month for the first FCA and $6.00/kW-month for the second FCA.

2.2.3 Resource Qualification

Because only resources with a capacity obligation are required to offer into the Day-Ahead and Real-Time Energy Markets, 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. Although generating, demand, and import resources all may participate in the FCA to receive a capacity supply obligation, the FCA treats new and existing capacity resources differently. Each type of resource has a distinctive qualification process designed to determine the amount of qualified capacity that 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).

Plan (RSP08) (http://www.iso-ne.com/trans/rsp/index.html) and NPCC criteria at http://www.npcc.org/documents/regStandards/Criteria.aspx (New York: NPCC Inc., 2007).

[51] 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.

[52] 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.

[53] 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.

2.2.3.1 Existing Capacity Resource Qualification

For existing resources, the qualification process relies on a resource's demonstrated performance over the previous five years. 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). The ISO also determines each resource's *winter-qualified capacity* for the winter portion of the commitment period (October through May).[54]

The ISO notifies existing resources of their qualified capacity at least two weeks before the existing capacity qualification deadline so that participants may verify that their qualified capacity is correct or 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 the 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.[55] The ISO may be required to submit a static delist bid on behalf of a resource if the resource's summer-qualified capacity were greater than its winter-qualified capacity because the resource would 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 INTMMU 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* are requests to retire the entire capacity of a generating capacity resource. These requests are subject to review for reliability impacts, but generating capacity resources that have had such requests denied must still retire as soon as practicable after the ISO has determined that the bid must be rejected for reliability reasons. Once submitted, nonprice retirement requests supersede any previous delist bids for the same capacity commitment period.

[54] The methodology for qualifying intermittent resource capacity, such as wind resources, is contained in *Market Rule 1*, Section III.13; http://www.iso-ne.com/regulatory/tariff/sect_3/09-2-16a_mr1_sect_13-14.pdf.

[55] "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.

- *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 multi-year 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.[56] 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.

INTMMU oversight. To address market power concerns, during the qualification process, the INTMMU reviews all delist bids that existing generators submitted at prices above the CONE 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 INTMMU to make these determinations; the INTMMU 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 INTMMU 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 INTMMU does not review ambient air delist bids and subsequent years of an administrative export delist bid. The INTMMU 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 reviewed for any potential reliability need, however, similar to all 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 will be entered into the auction. For delist bids that are excluded from the auction as a result of the INTMMU's review, the ISO will explain in the notification correspondence the specific reasons for not accepting the bid and the INTMMU's derivation of an alternate delist price.[57] The participant may opt to use this alternate price by informing FERC, subject to applicable market rules.

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 that previously were counted as existing capacity (including deactivated or retired resources), and incremental capacity from existing resources, may opt to be treated as new capacity resources in the FCM, subject to certain requirements.

[56] 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.

[57] FERC's FCM Settlement Agreement contained the thresholds for delist bids requiring INTMMU review: SMD Order. FERC Docket Nos. ER02-2330-000 and EL00-62-039 (September 20, 2002). p. 37.

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 prime mechanism for assessing demand-response project criteria because these projects have no interconnection impact. 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, many 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.

INTMMU oversight. Per *Market Rule 1*, the INTMMU 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

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[58] *Market Rule 1*, *Standard Market Design*, Section III (3.13.1) of FERC Electric Tariff No. 3, is available at http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

must contain supporting cost information for INTMMU review. If the INTMMU 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 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 whether its new capacity resource has been accepted for participation in the FCA, the qualified capacity of that resource, and the INTMMU'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 a descending-clock auction that begins at a high price with all suppliers offering (selling) qualified capacity from each of their resources. The auction proceeds in rounds, each with a lower price during which suppliers can continue to offer their capacity or withdraw. The auction concludes when the capacity remaining in the auction is less than or equal to the amount of resources needed (i.e., the ICR). The auction design is such that the lowest-priced new capacity that meets the region's future capacity needs will set the market price. Table 2-1 shows the results of a sample 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.

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
Final		$6.50	30,000	0

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

[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 at the price at which the last new capacity offer left the auction. The rule is described in detail in Market Rule I, Section III.13.2.7.8, available at http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

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 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 June 1, 2010, when the FCM transition period ends, resources with capacity obligations obtained in the FCAs will be paid the auction clearing prices and not the flat rate they received during the transition period.

Another key provision of the capacity payment structure is called *peak energy rent* (PER). Peak energy rent 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 if they are not producing energy when the LMP exceeds the PER threshold price. PER also discourages physical and economic withholding in the energy market because if a resource withholds to raise price, it does not earn energy revenues, while their foregone revenues are deducted from the capacity market settlement.

2.3 Reserve Markets

The New England system needs 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 that can deliver electric energy within 10 or 30 minutes.[60] 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.[61] Additional reserves must be available within 30 minutes to meet one-half of the second-largest system contingency (N-1-1). 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. The total amount of fast-start reserve is an estimate of the supply available to compete in the Forward Reserve Market.

In the New England system, resources are compensated for providing reserves through both the locational Forward Reserve Market (FRM), which offers a product similar to a capacity product, and real-time reserve pricing. The FRM sustains reserve capability through a competitive, intermediate-

[60] Some demand-side resources also can provide reserves. See Section 3.5.

[61] 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.

term auction market that selects resources likely to be unloaded most of the time and able to provide energy within a short time (i.e., provide reserve). In addition, real-time reserve pricing co-optimizes the use of resources for providing real-time reserves and electric energy. When a resource is ramped down and redispatched in real time to provide reserve capacity rather than electric energy, real-time reserve pricing recognizes the resource's opportunity cost. The redispatch also is reflected in the electric energy price set by the unit that was ramped up to replace the energy from the resource that was ramped down.

The New England system has reserve requirements for its locational FRM and real-time reserve pricing. 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.

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 was designed to attract the type of resources that provide the long-run, least-cost solution to satisfying off-line reserve requirements. To meet these requirements, the locational FRM compensates participants with flexible resource capacity located within specific subareas for making the type of electric energy market offers that would make them likely to be off line and thus available to provide energy within 10 or 30 minutes (i.e., fast-start units). Resources that meet this criterion are units that run infrequently throughout the year (i.e., they have low capacity factors).[62] These types of units, which provide reserve from an off-line state and thus at a very low incremental cost, include combustion turbines burning natural gas, diesel, kerosene, or jet fuel, and hydroelectric resources with water- storage capacity. The FRM also compensates the emergency ranges of units that have come on line without cost to the market, because they either are baseload units or have self-scheduled for the day.

To attract 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. Resources that normally are in merit below this level do not participate in the market because of the loss in revenue they would incur.[63] Resources designed to operate as peaking resources, on the other hand, face no losses. The threshold price, which is determined monthly, is designed to be higher than the LMP 97 to 98% of the time.[64]

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

[63] *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.

[64] The formula for determining the forward-reserve threshold price is fixed for the duration of the forward-reserve service 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.

Threshold prices should be set to match the marginal cost of low-capacity-factor, peaking resources with a capacity factor of 2 to 3%. 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 would then be dispatched only when the LMP exceeded the threshold price. If the threshold price is set too low, a forward-reserve-designated unit offered at the threshold price would be dispatched to provide electric energy more frequently and therefore would be unavailable to provide reserve. If this occurs more than 2 to 3% of the time, forward-reserve-designated resources would be dispatched more frequently than intended.[65] If participants expect LMPs to be higher than the threshold price on a regular basis, the reserve market could inadvertently attract resources that are better suited to provide electric energy than reserve.

To acquire appropriate forward-reserve obligations, the FRM features twice-yearly auctions for the summer and winter reserve periods (June through September and October through May, respectively). 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.[66] 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.

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

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 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 assure 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 that is acquired in the auction to account for real-time failures to start. Currently, the R-factor is set at 1.33.

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[65] 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 tighter than expected more frequently, thus requiring the dispatch of less efficient resources. In this case, LMPs will be higher.

[66] *Market Rule 1*, Section III.9.4, *Forward Reserve Auction Clearing and Forward Reserve Clearing Prices* (October 1, 2006); http://www.iso-ne.com/regulatory/tariff/sect_3/.

The cost of paying resources to provide reserves is allocated to market participants based on real-time load obligations in load zones.[67] These obligations are price-weighted by the relative forward-reserve clearing prices of the reserve zones that correspond to each load zone.[68]

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.[69] 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.[70] 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 simultaneously meet the system's requirements for electric energy and reserves. 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 when satisfying 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 4 (OP 4), *Action during a Capacity Deficiency*, if capacity is short and the system cannot be redispatched to maintain reserve.[71] Before allowing reserve to decline, the system will redispatch resources to maximize the amount of reserve 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 reserve and the replacement of this lost

[67] *Market Rule 1*, Manual 28, *Accounting* (December 1, 2007); http://www.iso-ne.com/rules_proceds/isone_mnls/.

[68] 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 load-serving entities 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.

[69] Refer to the ISO's RSP08 for additional information on operating-reserve requirements; http://www.iso-ne.com/trans/rsp/index.html.

[70] ISO Operating Procedure No. 8, *Operating Reserves and Regulation* (October 1, 2006); http://www.iso-ne.com/rules_proceds/operating/isone/op8/index.html.

[71] 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/.

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 reserve on the system. Local reserve shortages resulting from a capacity deficiency are rare. In most cases, reserve can be maintained through the process of redispatch and appropriate compensation through real-time reserve pricing.

2.3.3 Real-Time Scarcity Pricing

Reserve-constraint penalty factors (RCPFs) are the ISO's implementation of scarcity pricing and are administratively set. They are used to determine the highest level of redispatch costs the system is willing to endure to maintain reserves. Each constraint of a reserve requirement has a corresponding RCPF, shown in Table 2-2, which is used when the reserve requirement cannot be met.

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	$50

2.4 Regulation Market

Regulation is the capability of specially equipped generators and other sources to increase or decrease their generation 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.[72] 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 generation resources needed to manage system balancing, is to ensure that the ISO meets the North American Electric Reliability Corporation (NERC)'s *Real Power Balancing Control Performance Standard* (BAL-001-0) for balancing authority areas.[73] The primary measure used for evaluating control performance is Control Performance Standard 2 (CPS 2), which is as follows:[74]

[72] 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 Council of Texas (ERCOT).

[73] This standard (effective April 1, 2005) can be accessed at http://www.nerc.com/~filez/standards/Reliability_Standards.html#Resource_and_Demand_Balancing. Additional information on NERC requirements is available at http://www.nerc.com (Princeton, NJ: NERC, 2007).

[74] More information on NERC's Control Performance Standard 2 is available at ftp://www.nerc.com/pub/sys/all_updl/standards/rs/BAL-001-0.pdf.

> *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}.*[75]

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 Web site) are determined by hour and vary by time of day, day of week, and month.[76]

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 unit-specific opportunity cost payments. 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 (NCPC).[77] To maintain long-term reliability, the ISO 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 in supplement to 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, the Northeast Power Coordinating Council (NPCC), and the ISO through open stakeholder processes.[78] These requirements are codified in the NERC standards, NPCC criteria, and

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[75] The *area control error* 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.

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

[77] *Net Commitment Period Compensation* (NCPC) 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, see *Market Rule 1*, Section III, Appendix F, *Net Commitment-Period Compensation Accounting*, at http://www.iso-ne.com/regulatory/tariff/sect_3/.

[78] For more information on NERC standards, see https://standards.nerc.net (Princeton: NERC, 2008). For more information on NPCC standards, see http://www.npcc.org/regStandards/Overview.aspx (New York: NPCC Inc., 2009).

the ISO's operating procedures.[79] To meet these requirements, the ISO may commit resources in addition to those cleared in the Day-Ahead Energy Market.

The ISO may commit generation to allow the system to recover from the loss of the first contingency within the specified time period. Not having these resources committed to operate would pose a threat to the reliability of the system. Generators 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 runtime, and resources committed for peak hours often are still on line after the peak hours to satisfy 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 offers through electric energy market revenues, are paid one of the following types of compensation:

- First-contingency and second-contingency Net Commitment-Period Compensation (also referred to as first- and second-contingency reliability payments)
- Voltage reliability payments
- Distribution reliability payments

Systemwide first-contingency costs are financially settled through first-contingency reliability payments. Regional second-contingency commitments, reactive power for voltage control or support, and local transmission support are financially settled through second-contingency reliability payments, voltage reliability payments, and distribution payments, respectively.

2.5.1.1 Reliability Commitment Process

Electric energy market outcomes play an important role in the need for out-of-market commitments for reliability. While some commitments may be made 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 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 cost for start-up, no-load, and electric energy offers at minimum output. 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 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 and in relation to their offers. This compensation is based on generators' submitted offers for providing electric energy,

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

including start-up and no-load costs. This ensures that generators providing electric energy needed for reliability but that fail to recover their bid-in operating costs are paid for any expenses not recovered through their daily energy payments. 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 that are 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 II of the tariff (*Market Rule 1*).[80] 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.[81]

2.5.2 Reliability Agreements

Reliability Agreements provide 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 need for these agreements suggests that market prices do not fully and appropriately signal the locational need for new infrastructure.

The Reliability Agreements in effect through June 2010 in New England are for full cost of service—the generator recovers its fixed costs in a monthly payment and its variable costs through electric

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

[81] ISO New England Inc., *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.* FERC Docket No. ER07-921-000 (June 21, 2007).

energy offers made at short-run marginal cost. Variable costs not covered by energy market revenues are compensated through daily reliability payments. All capacity market revenues and energy market revenues received in excess of variable costs serve to reduce the monthly fixed-cost payment. Thus, the generator recovers no more than its fixed and variable costs.

2.6 Financial Transmission Rights

In New England, demand pays for electricity based on LMPs at one of the eight pricing zones (see Section 2.1.1). When transmission congestion occurs, varying levels of supply resources must be dispatched to address these constraints, which limits the flow of economic power and creates differences in the congestion components of the LMPs throughout the power grid. In some circumstances, this price separation may cause the ISO to collect more revenue from demand in congested areas than it will pay to generators supplying the electricity to those areas. This excess collection is called "congestion revenue," and market participants can bid for the rights to receive a share of this revenue. These rights are called "financial transmission rights" (FTRs).

A *financial transmission right* is a financial instrument that 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.[82] Participants can acquire FTRs for any path on the system that is 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 in the FTR auction price at the sink location price minus the source location price.

FTRs have two purposes:

- FTRs provide participants the ability to hedge the price volatility of day-ahead congestion.
- FTRs can serve as a financial mechanism to arbitrage the difference between a participant's expectations of congestion patterns and those of other FTR market participants.

In addition to providing benefits, holding FTRs is associated with risk because congestion is not always predictable. An outage or other change in the power system can cause congestion in the day-ahead market in the direction opposite from the prevailing net power flows the holder expected when it purchased the FTR in the auction. This *counterflow FTR* can turn an expected revenue stream into a liability.

Rather than directly allocating FTRs, each year, 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 for on-peak and off-peak periods during the year. The FTR auctions incorporate assumptions about the system based on expected transmission outages and FTR offers that will provide an efficient outcome; they are not based on private markets and bilateral trading. Efficient auction outcomes are those that result in average path profits that approach zero for both on-peak and off-peak FTRs.

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

The revenue from the FTR auctions is distributed to holders of Qualified Upgrade Awards (QUAs) and 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. Auction Revenue Rights are the mechanism used to distribute the remainder of the auction revenue to congestion-paying load-serving entities and transmission customers that have supported the transmission system.

For counterflow FTRs, the participant is paid from the ARR fund. This implies that the participant expects to make payments in amounts based on the unknown day-ahead market outcomes. Participants would acquire such expected obligations if they believed that the revenues they will receive in the auction will exceed the costs they will have to pay during the period the FTR is active. Counterflow FTRs can increase the efficiency of the auction outcome by increasing the supply of FTRs in the predominant direction of flows.

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 either can be 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. Payments are due to the CRBF from holders of FTRs with negative target allocations. 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.

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, which include demand-response resources and "other demand resources" (ODRs), are an important component of a well-functioning wholesale market. The equipment, systems, services, and strategies that make up 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 implemented by many customer facilities and aggregated as a single resource. *Other demand resources* consist of energy efficiency, load management, and distributed generation projects implemented by market participants at retail customer facilities. These resources tend to reduce end-use demand on the electricity network across many hours but usually not in direct response to changing hourly wholesale price incentives.

Demand resources of all types may provide relief from capacity constraints and promote more economically efficient uses of electrical energy; some can serve as reserve capacity. In the Forward Capacity Market (see Section 2.2), some types of demand-response resources and ODRs can compete for capacity credits and capacity transition payments similar to supply-side resources.

While the wholesale electricity markets account for differences in costs of supply that vary with time and location of consumption, demand resources account for differences in costs of service that vary with customers. 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 peak consumption. Others can provide reserves for themselves and others by offering to interrupt electricity usage on short notice. Still others may be able to provide emergency generation in response to capacity deficiencies or system emergencies. The ISO's special-purpose demand-response programs (or wholesale market integration of demand resources) differentiate demand-resource owners by cost and assign them different market rates. This type of customer differentiation arises naturally in competitive markets whenever customer costs differ and 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 ISO operates three real-time, reliability-activated demand-response programs and two price-activated demand-response programs, one based on day-ahead LMPs and one based on forecasted real-time LMPs. The reliability-activated demand-response programs are considered capacity resources by the FCM. This section describes the ISO's demand-side initiatives.

2.7.1 Reliability Programs

The real-time demand-response programs activated for reliability reasons are as follows:

- **Real-Time 30-Minute Demand-Response Program—**requires demand resources to respond within 30 minutes of the ISO's instructions to interrupt. Participants in this program include emergency generators with emissions permits that limit their use to times when reliability is threatened.

- **Real-Time Two-Hour Demand-Response Program—**requires demand resources to respond within two hours of the ISO's instructions to interrupt.

- **Real-Time Profiled-Response Program—**designed for participants with loads under their direct control that can be interrupted within two hours of the ISO's instructions to do so. Individual customers participating in this program are not required to have an interval meter. Instead, participants are required to develop a measurement and verification plan for each of their individual customers, which must be submitted to the ISO for approval.

The real-time demand-response programs for reliability are activated during zonal or systemwide capacity deficiencies to help preserve system reliability. Because these demand-response resources are available only during capacity deficiencies, they cannot qualify as operating reserves, such as 30-minute operating reserves (see Section 2.3).

The reliability programs are available at certain steps during the ISO's prescribed OP 4 actions during a capacity deficiency. The Real-Time Profiled-Response Program and the Real-Time Two-Hour Demand-Response Program are activated at OP 4 Action 3, an action designed solely to activate demand-response programs. The Real-Time 30-Minute Demand-Response Program is activated at Action 9 (to implement voluntary load reductions and declare a Power Watch) or Action 12 (to implement voltage reductions). The participant makes the choice of Action 12 or 9 at the time of enrollment. Customer-owned emergency generators usually have environmental permit limitations that require the system operator to implement voltage reductions, Action 12, before calling on those resources.

2.7.2 Price-Response Programs

The ISO's two price-response programs are as follows:

- **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 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 a participant enrolled in any of the three reliability-based demand-response programs or 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. The participant then is charged or credited at the real-time LMP for any deviations in curtailment during real time for the cleared interruptions.

2.7.3 Other Demand Resources

ODR projects in New England are as follows:

- **Energy efficiency—**Two thirds of the ODR projects are energy-efficiency projects. The energy-efficiency projects that qualify as ODRs and are eligible to receive FCM payments during the market transition period are paid on the basis of measured reductions. For example, a participant that, during a factory upgrade, replaces older, less energy-efficient lights with more energy-efficient lighting would be paid capacity transition payments for the difference in wattage usage coincident with the performance hours.
- **Load management—**While none of the ODR projects is a load-management project, the FCM rules recognize that such projects are qualified capacity eligible to receive FCM payments. Load management includes a combination of measures, systems, and strategies at end-use customer facilities that curtail electrical usage or shift electrical usage from peak hours to other hours while maintaining an equivalent or acceptable level of service at those facilities. These measures include, for example, energy management systems, load-control end-use cycling, load-curtailment strategies, chilled water storage, and other forms of electricity storage.
- **Distributed generation—**Distributed generation resources are "behind-the-meter" generators, such as combined heat and power systems, wind turbines, and photovoltaic generation. Roughly one-third of the ODR projects consist of distributed generation projects, although they account for a smaller percentage of the total capacity. Distributed generation resources are paid on the basis of measured electricity reduction at the meter. The capacity value is the generator output during performance hours taken from required interval meters on the generation equipment.

ODRs typically are nondispatchable assets, which perform differently than real-time demand-response assets. Currently, all registered ODRs operate under ODR performance hours, which are on-peak periods between 5:00 p.m. and 7:00 p.m. nonholiday weekdays in December and January, and between 1:00 p.m. and 5:00 p.m. nonholiday weekdays in June, July, and August.

2.8 Market Oversight and Analysis

The market monitoring structure implemented by the ISO relies on the ISO's Internal Market Monitoring Unit and the Independent Market Monitoring Unit, 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 Markets Committee of the ISO Board of Directors. Additionally, the INTMMU seeks regular input from the IMMU 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 INTMMU 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 INTMMU from becoming isolated and support the ISO's responsibility to ensure that the New England markets and prices are fair, transparent, and competitive.

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

2.8.1 Role of Market Monitoring

Through the following five general monitoring activities, the INTMMU 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*[83]
- Investigating participant behavior that is not explicitly precluded by existing tariff provisions 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 when necessary
- Evaluating new ISO initiatives and market design proposals to ensure that the revisions will support the efficient operation of competitive wholesale electricity markets

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

- Identifying potential anticompetitive behavior by market participants

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

- 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)[84]
- 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
- 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. If the INTMMU finds a potential violation of EPAct or the market-behavior rules, it is obligated to make a referral to FERC.

2.8.2 Market Monitoring and Mitigation

As specified in *Market Rule 1*, the ISO 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 ISO 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.

[84] *Energy Policy Act of 2005*, Pub. L. No.109-58, Title XII, Subtitle B, 119 Stat. 594 (2005) (amending the *Federal Power Act*); http://www.energy.gov/about/EPAct.htm.

Section 3
Energy Market

A competitive market requires a market structure in which many competitors participate in the market and none of the competitors is large enough to affect price. Because the New England energy markets have many competitors and because no single competitor is large enough to affect the market price, the regionwide market structure provides the foundation for a competitive market. Additionally, mitigation measures provide protection when and where inadequate transmission or peak load levels create the possibility of noncompetitive behavior.

This section describes the outcomes and competitiveness of the ISO's Day-Ahead and Real-Time Energy Markets, including congestion revenues, Financial Transmission Rights, and demand resources. The main factors that affected the electric energy markets in 2008 were lower economic activity that resulted in lower electric energy consumption and generally higher and more volatile fuel prices. According to the INTMMU's analyses, the electric energy market outcomes in 2008 were consistent with a competitive market. Section 2.1 summarizes the functioning of these markets. More detailed information on prices, net interchange with neighboring areas, and average heat rates is contained in the data appendix, Section 8.1.

3.1 Market Competitiveness and Efficiency

To evaluate competition in New England markets, the ISO uses three primary metrics widely used to assess competition in the energy markets:

- **Competitive benchmark price model—**models and compares model-derived prices based on competitive offers with model-derived prices based on actual offers. The difference also is used to calculate the Quantity-Weighted Lerner Index (QWLI) to assess the competitiveness of market outcomes.

- **Herfindahl-Hirschman Index (HHI)—**measures market concentration of generating capacity. An HHI below 1,000 indicates a low concentration and therefore a market less susceptible to market power.

- **Residual Supply Index (RSI)—**measures the hourly percentage of load in megawatt-hours (MWh) that can be met without the largest supplier. Such suppliers are termed "pivotal" and often can affect market prices.

This section presents analyses of competitive market conditions during 2008 for the ISO's electric energy markets. It includes analyses of concentration, how fuel prices affect electricity prices, and out-of-merit generation.

3.1.1 Competitive Benchmark Analysis

The competitive benchmark (benchmark price) is a model-derived estimate of the market-clearing price that would result if all market participants offered their electric energy at marginal cost, the market operated with perfect efficiency, and the system was unconstrained.[85] The model derives the

[85] 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

benchmark price in each hour by estimating the additional cost for the next megawatt (e.g., incremental cost) of the least expensive generating unit capable of producing one more megawatt. The benchmark price accounts for production costs, including environmental and variable operations and maintenance (O&M) costs, unit availability, and net imports.

Table 3-1 compares the annual average benchmark price with a second modeled price, an offer-intercept price. The offer-intercept price is derived using the same model as the benchmark price, but instead of using generator costs, it uses generators' actual supply offers. Comparing the aggregate bid-intercept price with the benchmark price over time can help assess the competitiveness of the market. The closer the two measures, the more competitive the market is likely to be.

Table 3-1
ISO Model Market Price Measures

Price Measure	2008 Price ($/MWh)	Quantity-Weighted Lerner Index (%)[a]					
		2003	2004	2005	2006	2007	2008
Competitive benchmark price	$77.86						
Aggregate offer-intercept price	$76.94	−4	−6	1	1	2	−1

(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].

The metric used to compare the different price estimates is the Quantity-Weighted Lerner Index (QWLI), which is 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 treats the model-based offer-intercept price as the "market price" in the Lerner index.

Table 3-1 shows that the QWLI decreased from 2% in 2007 to −1% in 2008. This is a small year-to-year change, given that the QWLI, while a useful measure of market competitiveness, is subject to modeling error because of the necessary simplifying assumptions and the need to rely on estimates of generator-input cost and efficiency (e.g., environmentally limited units are not explicitly considered; hydroelectric units are assumed to be perfectly competitive). Therefore, small year-to-year changes are likely to mean little change in the market's competitiveness. Trends in the index over time or large movements would indicate changes in the market's competitiveness. The results of the model suggest that the market continued to behave competitively through 2008.

The system load-weighted average real-time Hub price for 2008 was $83.91/MWh, about 9% higher than the offer-intercept price.[86] The model calculates the aggregate offer-intercept price using the actual offer data used in the real-time dispatch and real-time prices. Therefore, the difference between

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.)

[86] The system load-weighted average Hub price is used because it provides the closest conceptual match to the prices calculated by the benchmark model.

the actual Hub price and the aggregate offer-intercept price is due to modeling error in the competitive benchmark model. In 2009, the INTMMU will work to improve the benchmark model.

3.1.2 Market Concentration

Figure 3-1 shows the generation capability of the 10 lead participants with the largest portfolios during 2008. As in the previous year, the largest portfolio was owned by Dominion Energy Marketing, with 4,800 MW; followed by FPL Energy Power Marketing, with 3,000 MW; and Boston Generating, with 2,600 MW. New England's largest provider, Dominion, has a 15% market share, while FPL has a 10% market share. As of July 1, 2008, 87 suppliers were participating in the New England energy markets.

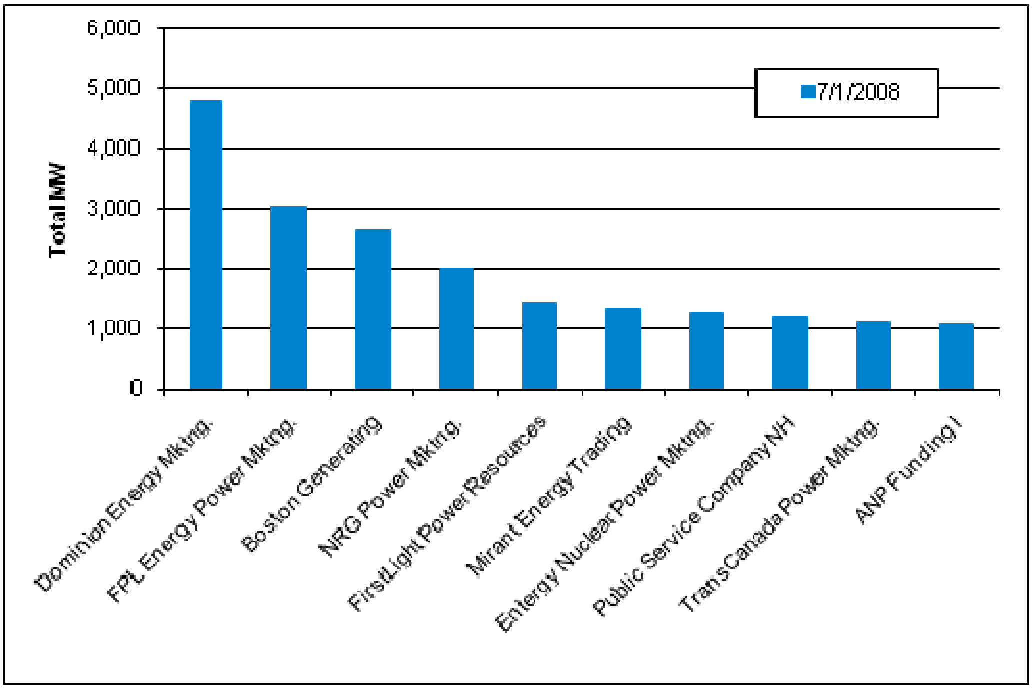

Figure 3-1: Generation capacity by lead participant, 2008, 1,000 MW and above.

Market concentration is a function of the number of firms in a market and their respective market shares. For electricity markets, shares are measured by megawatts of generating capacity. 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:[87]

- Not concentrated (HHI below 1,000)
- Moderately concentrated (HHI between 1,000 and 1,800)
- Highly concentrated (HHI above 1,800)

[87] The Department of Justice (DOJ) defines markets with an HHI below 1,000 points to be unconcentrated, an HHI between 1,000 and 1,800 points to be moderately concentrated, and an HHI above 1,800 points to be highly concentrated. (U. S. Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines*, April 8, 1997; http://www.usdoj.gov/atr/public/guidelines/horiz_book/15.html).

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

Monthly regionwide HHIs for New England internal resources, based on summer capabilities and the resources' lead participant, averaged 620 in 2008. This result indicates that the New England electric energy markets are well within the "not concentrated" range. However, regionwide HHI is not a complete indicator of market concentration in wholesale electricity markets because it understates the likelihood of market power exercise in two ways. One, it ignores the effect that transmission constraints can have on the market, which can give resources in constrained areas market power in load pockets.[88] Two, the HHI does not recognize the electric industry's currently inelastic demand curve and the inability of electricity users to economically store electricity, thus permitting prices to rise in the short term. Regionwide HHI also may overstate market concentration because it does not account for contractual entitlements to generator output, which can decrease the incentive for resources to exercise market power. Nonetheless, HHI is still a useful indicator to monitor.

3.1.3 Residual Supply Index Analysis

The Residual Supply Index measures the percentage of demand (in MW) that can be met without the largest supplier. It indicates the potential ability of individual bidders to influence the market-clearing price. If the RSI exceeds 100%, other suppliers have sufficient capacity to meet demand without any generation from the largest supplier. If 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, in theory, drive prices above the competitive level, subject only to offer caps, mitigation measures, and the price elasticity of demand.

The RSI is considered a more robust indicator of short-term market competitiveness than the HHI. Electricity markets are characterized by rapidly changing market conditions and continuous balancing of essentially nonstorable supply and inelastic demand. Studies conducted by the California ISO suggest an inverse relationship between the RSI and the price-cost markup, which is similar to the market metric developed in the competitive benchmark analysis (described in Section 3.1.1).[89] That is, as RSIs fall, markups tend to increase.

Table 3-2 shows the number of hours in each month of 2008 that the systemwide RSI was below 100% and 110%. 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 pivotal suppliers existed at the system level during a total of 51 hours during two months in 2008, a decrease from 2007 when 115 hours were spread over five months. This slight improvement in the level of competition is likely due to lower loads throughout the year. All the hours with pivotal suppliers occurred during high-demand summer days (June and July).

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[88] *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).

[89] Anjali Sheffrin, *Preliminary Study of Reserve Margin Requirements Necessary to Promote Workable Competition* (California ISO, November 19, 2001). Revision is available at http://www.caiso.com/docs/2001/11/20/200111201556082796.pdf.

Table 3-2
Systemwide Residual Supply Index, 2008

Month	Number of Hours RSI < 100%	Number of Hours RSI < 110%	Average Monthly RSI	Maximum RSI	Minimum RSI
Jan	0	3	141	192	107
Feb	0	0	145	188	112
Mar	0	0	140	174	118
Apr	0	6	132	174	107
May	0	43	139	196	100
Jun	24	59	137	191	87
Jul	27	133	132	188	94
Aug	0	10	144	193	108
Sep	0	30	142	195	104
Oct	0	7	141	195	107
Nov	0	10	139	334	104
Dec	0	10	144	199	105
Total	51	311	139	334	87

To better understand potential local market power caused by import constraints, the INTMMU analyzed local RSIs for the months of June and July 2008. The analysis included the SWCT, CT, and NEMA/Boston reserve zones. These areas were chosen because they often are import constrained or have a high local HHI. Table 3-3 shows very low RSIs and many hours with a pivotal supplier, indicating significant potential for the exercise of local market power. Market mitigation rules for constrained areas are vital for preventing suppliers from exercising market power during these conditions.

Table 3-3
Local Area RSI Calculations for Selected System Interfaces, 2008

Reserve Zone	Month	Number of Hours RSI < 100%	Number of Hours RSI < 110%	Average Monthly RSI	Maximum RSI	Minimum RSI
SWCT	June	134	270	120	176	75
	July	144	320	120	169	88
CT	June	355	481	105	153	68
	July	445	540	98	146	71
NEMA/Boston	June	676	717	76	113	47
	July	679	737	78	114	51

3.1.4 Comparison of Fuel Prices and Electric Energy Prices

Another indicator of market competitiveness is whether electricity prices change in response to changes in their input costs. Since fuel costs are by far the largest short-term cost of generating electricity, in competitive markets, electricity prices should change as fuel prices change. This section compares the average monthly percentage change in the prices of electricity and natural gas from 2007 to 2008. The results indicate that at the systemwide level, electricity prices move in near lock step with fuel prices, supporting the conclusion that the electricity market is competitive.

Figure 3-2 shows the percentage change in monthly natural gas prices from 2007 to 2008 and the percentage change in monthly real-time electricity prices, demonstrating a close association between natural gas prices and electricity prices. The deviation from the pattern in August and September was caused by a period in 2007 when oil-fired units set price during higher loads.

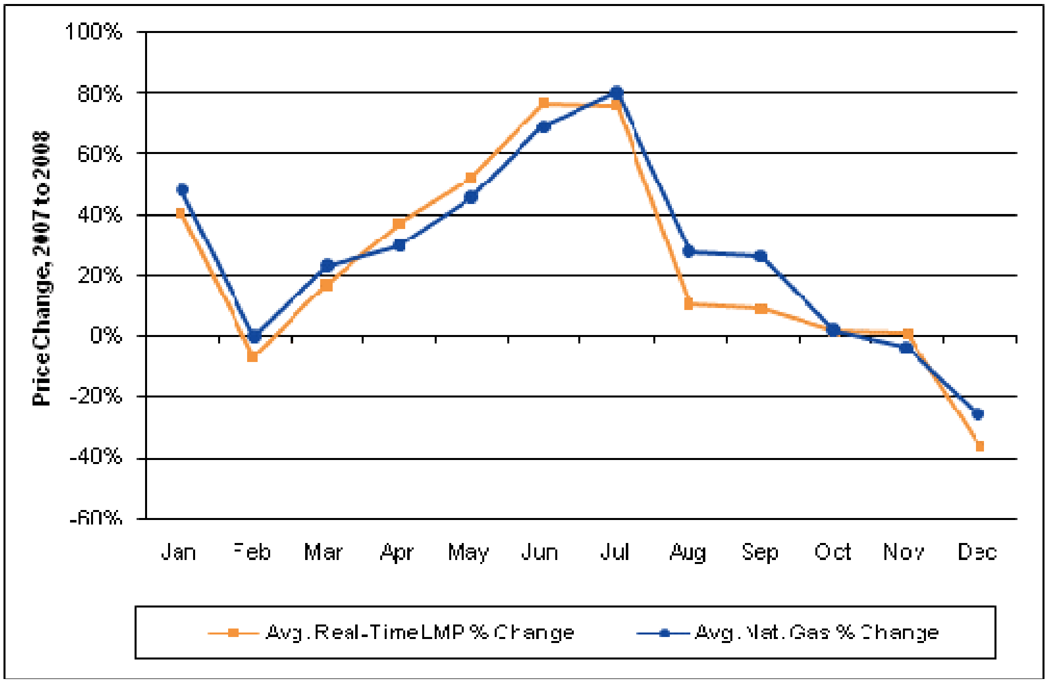

Figure 3-2: Percentage change in real-time LMPs and natural gas, 2007 to 2008.

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

Figure 3-3 shows that average annual input fuel prices continued increasing through 2008. The prices of oil and natural gas, which account for 63% of the region's capacity and 43% of generation output, have increased significantly since the market opened in 1999. Average annual prices have increased by about 250% for natural gas, 400% for No. 6 oil (1%), and almost 500% for No. 2 oil.[90] Coal prices increased by about 300% over this time period.

[90] 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.

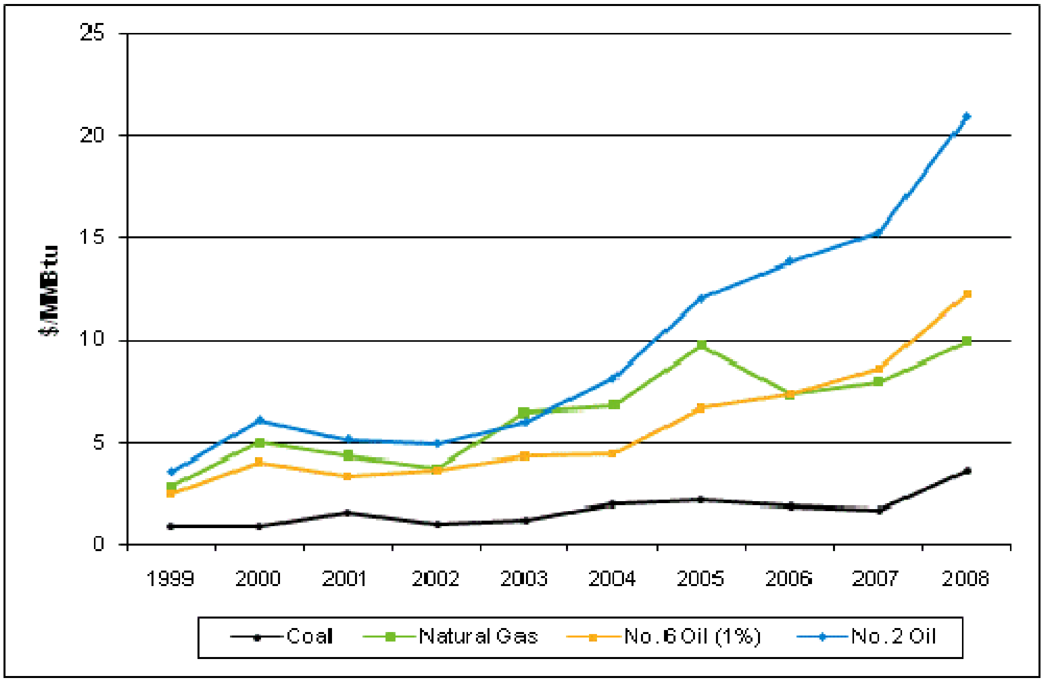

Figure 3-3: Average annual fuel prices for selected input fuels, 1999 to 2008.

Sources: Natural gas price information was provided by ICE. Coal and oil prices were provided by Argus Media.

Along with the long-term general increase in fuel prices, the electricity market faced fuel-price volatility during 2007 and 2008. As shown in Figure 3-4, in early 2008, monthly average fuel prices continued an increase that began in late 2007, peaking in summer 2008. By the end of the year, prices declined to 2007 levels or below. During the week of July 4, 2008, the average cost of imported crude oil was $142.52/barrel.[91] This cost fell to $32.98 in the last week of 2008. Despite this drop, average fuel prices in 2008 were the highest since the opening of electricity markets in New England in 1999.

Not only were fuel-price levels volatile, but both the sign and magnitude of the price difference between natural gas and No. 6 oil (1%) varied over the two-year period, as shown in Figure 3-4. The relationship between No. 6 oil (1%) and natural gas prices is important in New England's wholesale electricity markets for two reasons. First, at lower oil prices, efficient oil generators can compete with less efficient natural gas generators, lowering electricity prices. Second, when oil units are needed for reliability reasons and are not in merit, lower oil prices would lead to lower out-of-market payments for reliability. In early 2007, No. 6 oil (1%) was slightly less expensive than natural gas; it became more expensive than natural gas in spring 2007 and remained so until late 2008, when its price fell below natural gas prices.

[91] Energy Information Administration, "Weekly Cushing, Oklahoma (OK), West Texas Intermediate (WTI) Spot Price, Free on Board (FOB), in $/barrel" (Washington, DC: U.S. DOE, March 4, 2009); available at http://tonto.eia.doe.gov/dnav/pet/hist/rwtcW.htm.

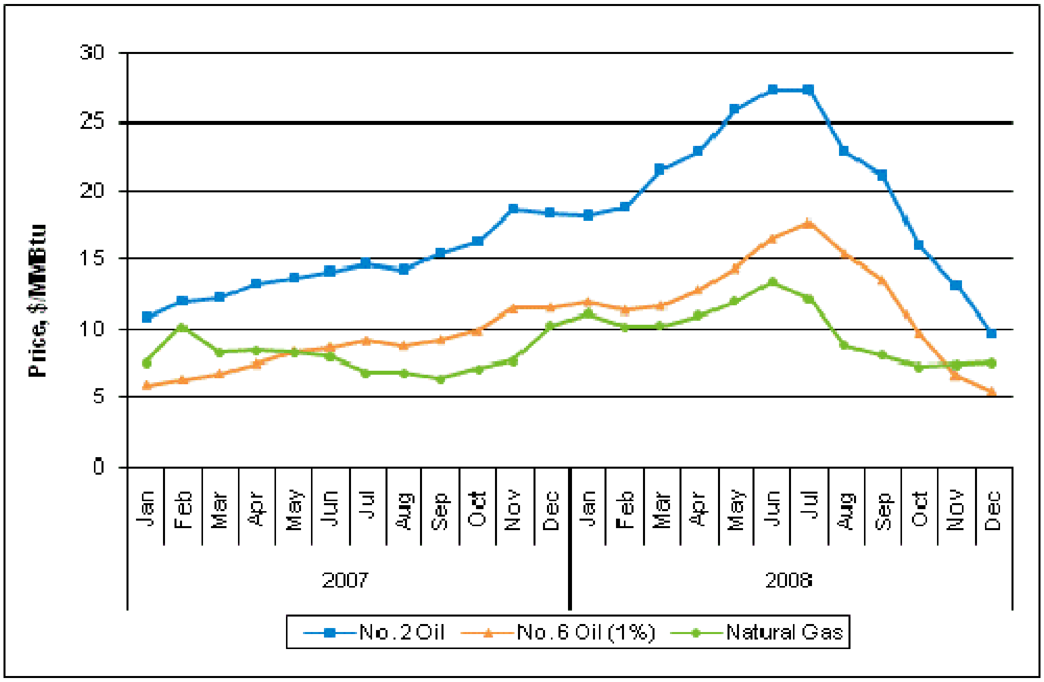

Figure 3-4: Average monthly fuel prices for selected input fuels, 2007 and 2008.

Sources: Natural gas price information was provided by ICE. Coal and oil prices were provided by Argus Media.

3.2 Day-Ahead Energy Market

This section presents the results of the day-ahead market in 2008. It examines prices and the types of demand and supply participating in the market.

3.2.1 Day-Ahead Prices

Table 3-4 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 2007 and 2008. The average day-ahead Hub price in 2008 was higher than in 2007. The increase in LMPs from 2007 to 2008 primarily was due to increased fuel prices. During 2008, average day-ahead zonal prices did not vary more than about $2/MWh from the Hub, with the exception of Maine and Connecticut. Average LMPs in Maine were about $4.50/MWh lower than the Hub, in part, due to negative marginal-loss costs. Import constraints into Connecticut led to higher prices in Connecticut; the average CT load zone LMPs were $4.33/MWh greater than the average Hub price. These patterns are similar to the price differences in 2007.

Table 3-4
Simple Average Day-Ahead Hub Prices and Load-Zone Differences for 2007 and 2008

Location/Load Zone	2007	2008
Hub	$67.97	$80.43
Maine	−$3.62	−$4.45
New Hampshire	−$1.14	−$1.32
Vermont	$1.38	$0.47
Connecticut	$3.73	$4.33
Rhode Island	−$1.81	−$1.17
SEMA	−$0.02	$2.03
WCMA	$0.58	$0.64
NEMA	−$1.34	−$0.67

3.2.2 Day-Ahead Demand for Electric Energy

Figure 3-5 shows the total percentage of day-ahead cleared demand by demand categories. Fixed demand has remained fairly consistent as a percentage of total cleared demand, ranging from almost 60% in 2006 to about 56% in both 2007 and 2008. In addition to fixed demand, price-sensitive demand also has decreased as a percentage of cleared demand. Higher percentages of virtual demand bids and exports offset these decreases.

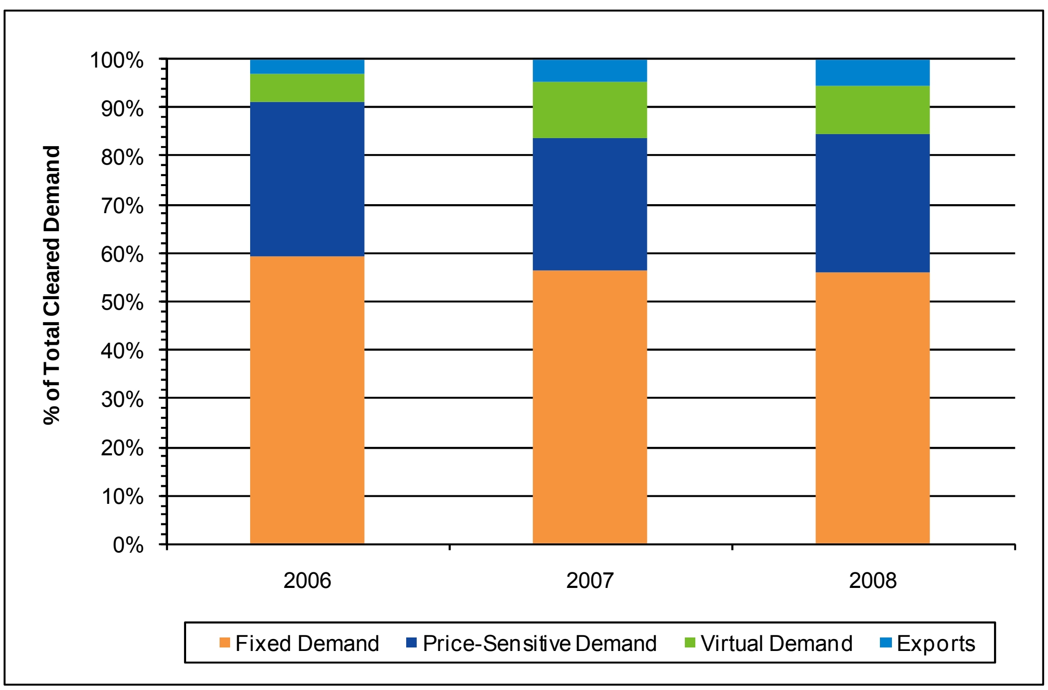

Figure 3-5: Day-ahead demand by category.

3.2.3 Day-Ahead Supply of Electric Energy

Figure 3-6 shows the percentage of submitted and cleared day-ahead fixed and price-sensitive supply offers, virtual supply, and imports for 2006, 2007, and 2008. Day-ahead cleared imports increased from 2007 to 2008 and accounted for over 10% of day-ahead supply in 2008. Cleared price-sensitive supply has decreased each year since 2006. Each year, virtual supply has been greater than virtual demand. The volume of both submitted and cleared price-sensitive imports has increased each year from 2006 to 2008.

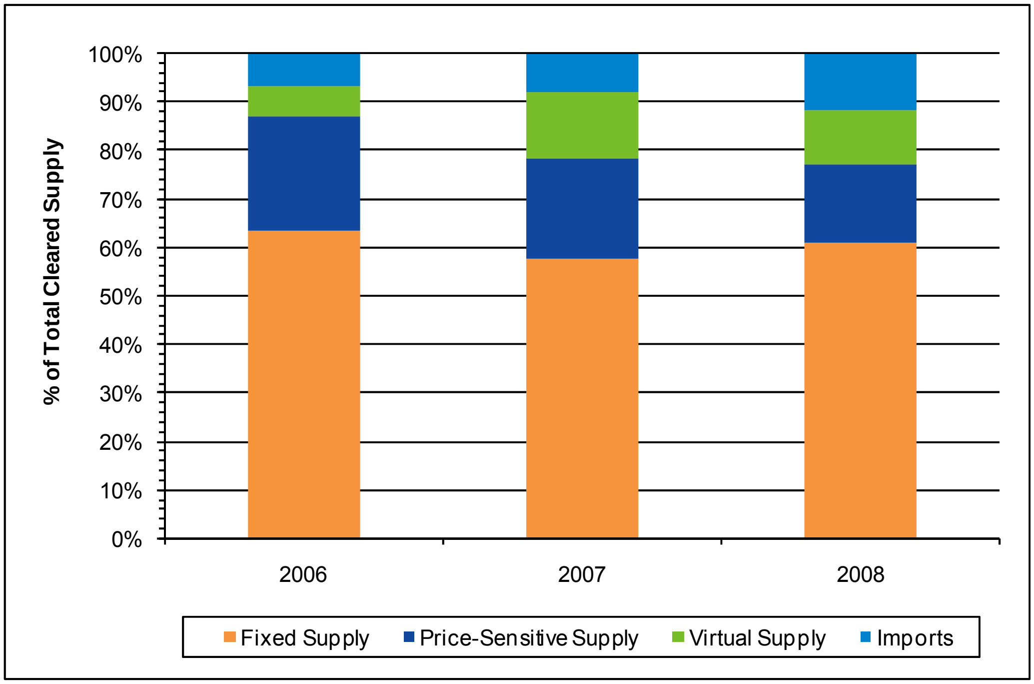

Figure 3-6: Day-ahead supply as a percentage of total cleared supply.

During all three years, fixed demand was roughly equal to fixed supply in the range of 60% for both price-sensitive supply and demand. 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. On average, price-sensitive supply and demand bids accounted for 35% to 40% of the total cleared demand.

3.3 Real-Time Energy Market

This section presents the results of the Real-Time Energy Market in 2008. It reviews prices, the demand for electricity, total generation output, and imports and exports and compares day-ahead and real-time prices.

3.3.1 Real-Time Prices

Figure 3-7 shows average monthly real-time Hub prices for New England over the past three years. The figure shows that prices during 2008 were higher than prices in 2006 and 2007 through August, when they dropped to the previous years' levels.

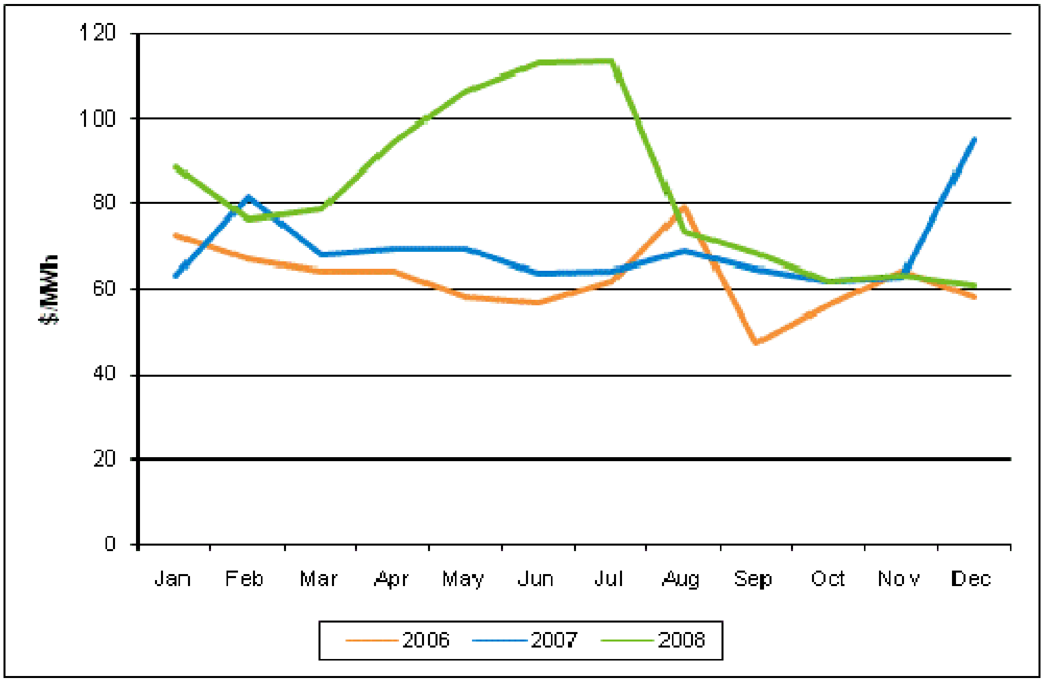

Figure 3-7: Average monthly real-time Hub prices, 2006 to 2008.

Table 3-5 shows real-time electricity prices for the Hub and the difference between the Hub and each of the eight New England zones for 2007 and 2008. The average Hub price during 2008 was higher than during 2007. The increase in Hub LMPs from 2007 to 2008 primarily was due to increased fuel prices. During 2008, average real-time zonal prices did not vary more than about $2.00/MWh from the Hub, with the exception of Maine and Connecticut. Average LMPs in Maine were about $5.20/MWh lower than the Hub, in part, due to negative marginal-loss costs. Average LMPs for the CT load zone were almost $3.00/MWh higher than the Hub, as a result of import constraints into Connecticut.

Table 3-5
Simple Average Real-Time Hub Prices and Load-Zone Differences for 2007 and 2008

Location/Load Zone	2007	2008
Hub	$66.72	$80.56
Maine	−$3.07	−$5.20
New Hampshire	−$0.73	−$1.24
Vermont	$1.39	$0.38
Connecticut	$5.03	$2.78
Rhode Island	−$1.67	−$1.10
SEMA	−$0.53	$0.79
WCMA	$0.77	$0.66
NEMA	−$1.12	−$0.25

3.3.2 Fuel-Adjusted Price

The INTMMU calculated the 2008 fuel-adjusted electricity price by adjusting the 2008 marginal LMPs by the ratio of the 2008 daily fuel prices to the year 2000 average monthly fuel prices of the corresponding market intervals and marginal fuel types. The results of this approach indicate the impact of fuel prices on electricity prices, but it only provides a rough estimate because it does not account for the impact that changes in relative fuel prices, load growth, and resource mix since the year 2000 have had on system dispatch and pricing. Figure 3-8 shows average actual and fuel-adjusted real-time electric energy prices for 2000 to 2008. High fuel prices in 2005, caused in part by Hurricanes Katrina and Rita, caused the large price increase in that year. Changes since 2005 also were largely driven by fuel prices.

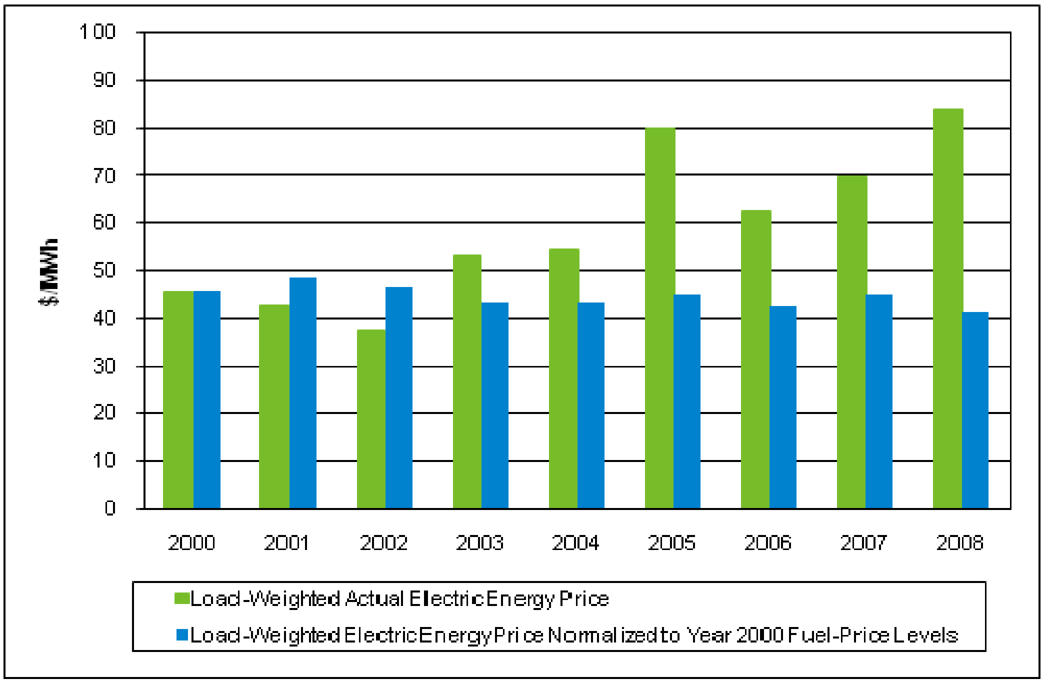

Figure 3-8: Actual and fuel-adjusted average real-time electric energy prices, 2000 to 2008.

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

Unlike the system load-weighted average annual price of electric energy, which rose 21% from the 2007 price, the fuel-adjusted price in 2008, at $41/MWh, was 8% lower than the price in 2007.[92] The decline in the fuel-adjusted price from 2007 to 2008 is largely attributable to two factors: the decrease in energy consumption and an increase in hydroelectric generation, which rose by 19% in 2008.[93]

[92] The average annual load-weighted electric energy price shown in this analysis is a system load-weighted average of Hub prices. This formulation of annual price is used to provide consistency with the methodology used to estimate the fuel-adjusted price, which adjusts the Hub price by the price of the type of fuel used to power the marginal generator.

[93] Both factors resulted in more efficient, lower-cost resources setting the price. Lower loads meant that more efficient resources satisfied demand. Since more rain fell during most months in 2008 than in 2007 and, in general, that hydroelectric energy in New England is run-of-river with limited storage, increased hydroelectric energy was offered into the market at the bottom of the supply curve, which also increased the efficiency of the resources that serve load.

The benchmark model described in Section 3.1.1 was used to gauge the combined impact on prices of lower load levels and higher hydroelectric output relative to 2007. The analysis generated a base case using the offer-intercept method also described in Section 3.1.1 (i.e., using daily supply offer curves and hourly loads from 2008 to calculate hourly prices). A new set of hourly prices was then calculated using a set of modified 2008 supply curves and 2007 hourly load levels. The supply curves were modified to estimate the impact on 2008 supplies of generally higher hydroelectric output during 2008 than 2007. This impact was modeled by shifting the intersections of the daily supply curves with the horizontal axes to the left by an amount equal to the average daily change in hydroelectric output. Because the majority of this increase in supply is generated by run-of-river projects, the hydro energy can reasonably be assumed to have been self-scheduled. A set of prices was then determined as the intersections of the daily modified 2008 supply curves with 2007 hourly load levels. Had 2008 load and hydroelectric output been similar to 2007 levels, the model estimated that average 2008 fuel-adjusted prices would have increased by about $5.00/MWh, or a 7% increase over the 2008 base case. Monthly average prices are shown in Figure 3-9.

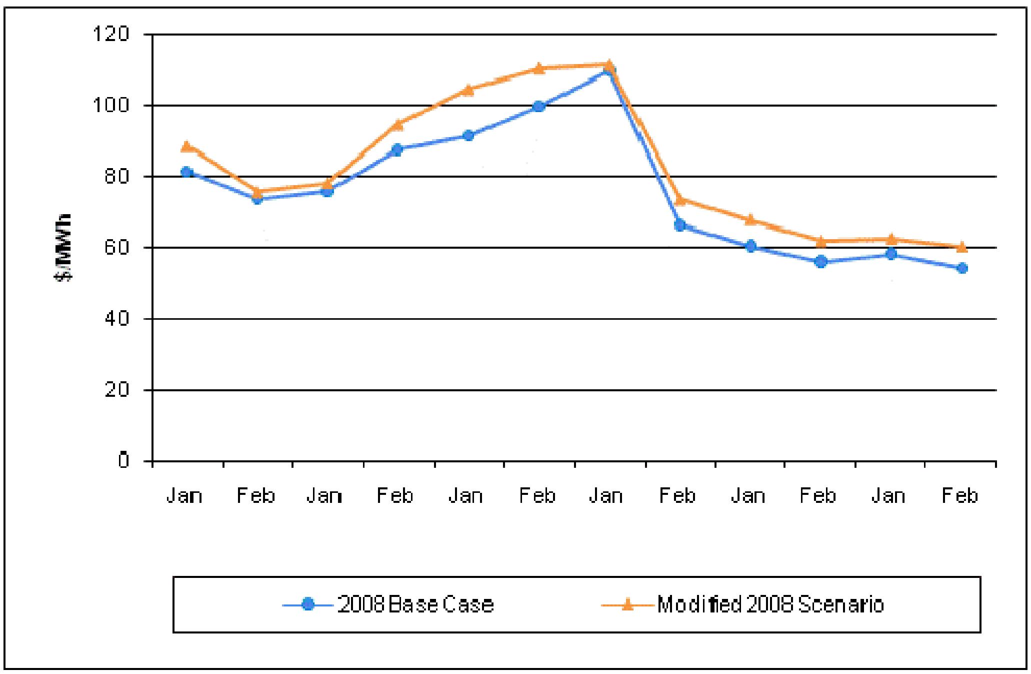

Figure 3-9: Monthly modeled prices for 2008 base case and modified 2008 scenarios.

3.3.3 Difference between Day-Ahead and Real-Time Prices

The maps in Figure 3-10 show the average annual nodal LMPs as color gradations from blue, representing $70/MWh or less, to red, representing prices of $90/MWh and higher. Southeast Massachusetts and Southwest Connecticut had the highest average day-ahead prices, while Maine had the lowest prices. The biggest difference between day-ahead and real-time prices occurred in Southeast Massachusetts due to the need to operate a resource for reliability reasons in that area. The resource was not included in the day-ahead market but was included in the real-time market, lowering prices in real time. While virtual transactions reduced the difference between day-ahead and real-time prices in SEMA somewhat, they did not fully close the gap.

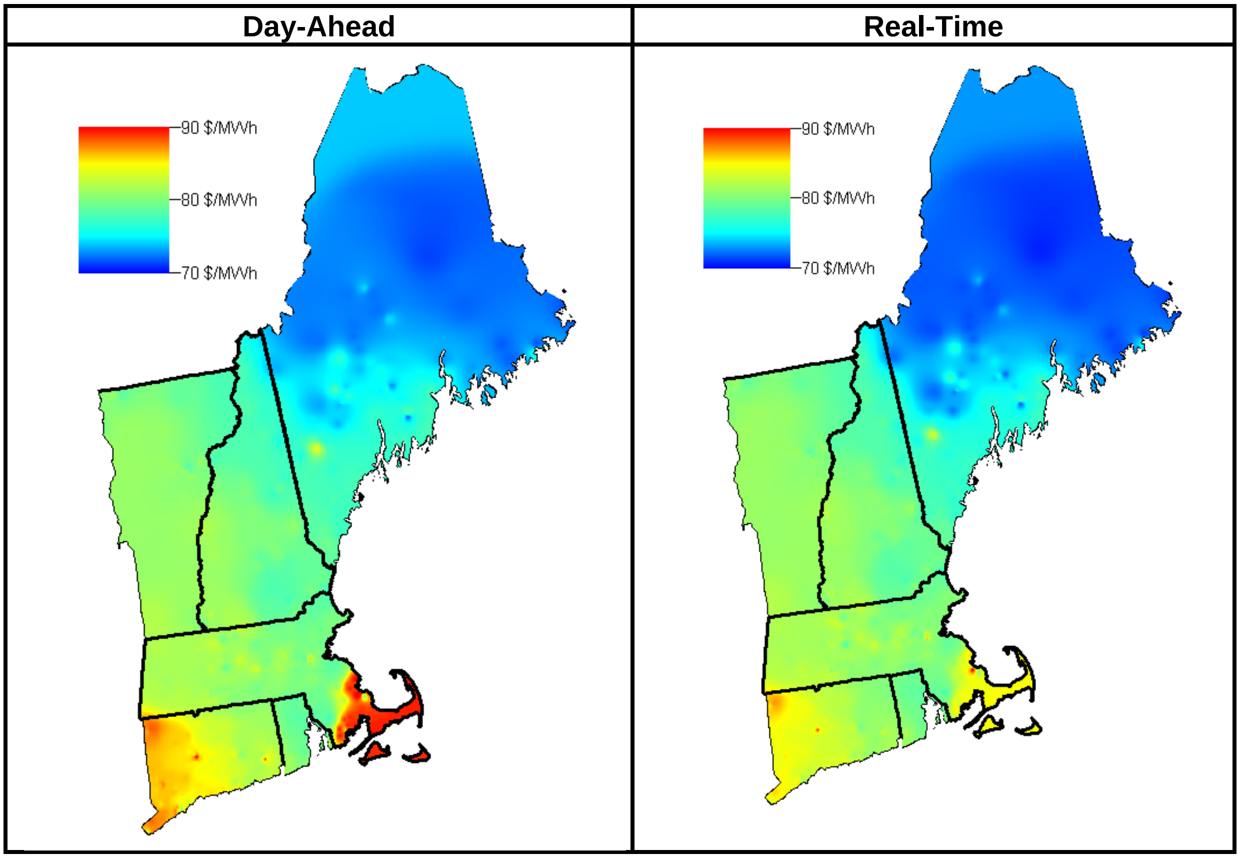

Figure 3-10: Average nodal prices, 2008, $/MWh.

Note: The extreme maximum values of nodal LMPs are not included in the scale to provide more resolution in price difference of the figures. The actual maximum average annual LMP for the day-ahead market was $97.35/MWh, and the true minimum was $71.31/MWh. The actual maximum for the real-time market was $80.27/MWh, and the actual minimum was $70.64/MWh.

3.3.4 Wholesale Prices in Other Northeastern Pools

Comparing price levels across interconnected power pools provides a context for evaluating price levels in New England. Table 3-6 compares the 2006, 2007, and 2008 average system prices for the three northeastern ISOs—ISO New England, the New York ISO (NYISO), and PJM Interconnection.[94] The average prices for 2008 were higher in all three pools. ISO New England and NYISO average prices are calculated hourly system prices based on locational prices and locational loads, while PJM prices are published hourly system prices.[95] New York had the highest average prices, while PJM had the lowest.

[94] PJM Interconnection LLC is 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.

[95] See PJM's Web site at http://www.pjm.com and NYISO's Web site at http://www.nyiso.com.

Table 3-6
Comparison of Day-Ahead and Real-Time Prices for Eastern ISOs

	Day Ahead			Real Time		
Date	**NE**	**NY**	**PJM**	**NE**	**NY**	**PJM**
2006	$61.80	$65.70	$48.10	$60.46	$65.13	$49.27
2007	$68.27	$70.65	$54.76	$67.48	$70.84	$57.67
2008	$81.16	$84.37	$66.12	$80.56	$83.17	$66.44

Note: The 2008 real-time price for New England is the price used in the simple average of Real-Time Energy Market Hub prices.

3.3.5 Real-Time Demand

Table 3-7 shows that the actual and weather-normalized demand for electricity each decreased by about 2% from 2007 to 2008.[96] Annual demand for electricity has not yet regained its 2005 level of 136.4 gigawatt-hours (GWh). The drop in electric energy consumption from 2007 was caused by three factors: a decline in economic activity, more efficient use of electricity, and higher prices. In contrast to the decline in energy consumption, weather-normalized peak demand increased. This increase means that the region's load factor continued to decline in 2008.[97]

Table 3-7
Annual and Peak Electric Energy Statistics, 2005 to 2008

	2005	2006	2007	2008	% Change
Annual NEL (GWh)[(a)]	136,355	132,087	134,466	131,736	−2.0%
Normalized NEL (GWh)	134,347	132,547	134,109	131,501	−1.9%
Recorded peak demand (MW)	26,885	28,130	26,145	26,111	−0.1%
Normalized peak demand (MW)	26,545	26,940	27,460	27,765	1.1%

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

As illustrated in Figure 3-11**,** New England monthly temperatures in 2008 generally were consistent with long-term averages. January, June, and August were the only months in which the 2008 monthly average deviated from the long-term average by more than 2°Fahrenheit (F). January and June were warmer than normal, and August was cooler.[98]

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

[97] The *load factor* is the ratio of average hourly demand during a year to the peak hourly demand.

[98] Weather information is available at http://www.weather.gov/climate/index.php?wfo=box. Normalized climate values cover 1971 to 2000.

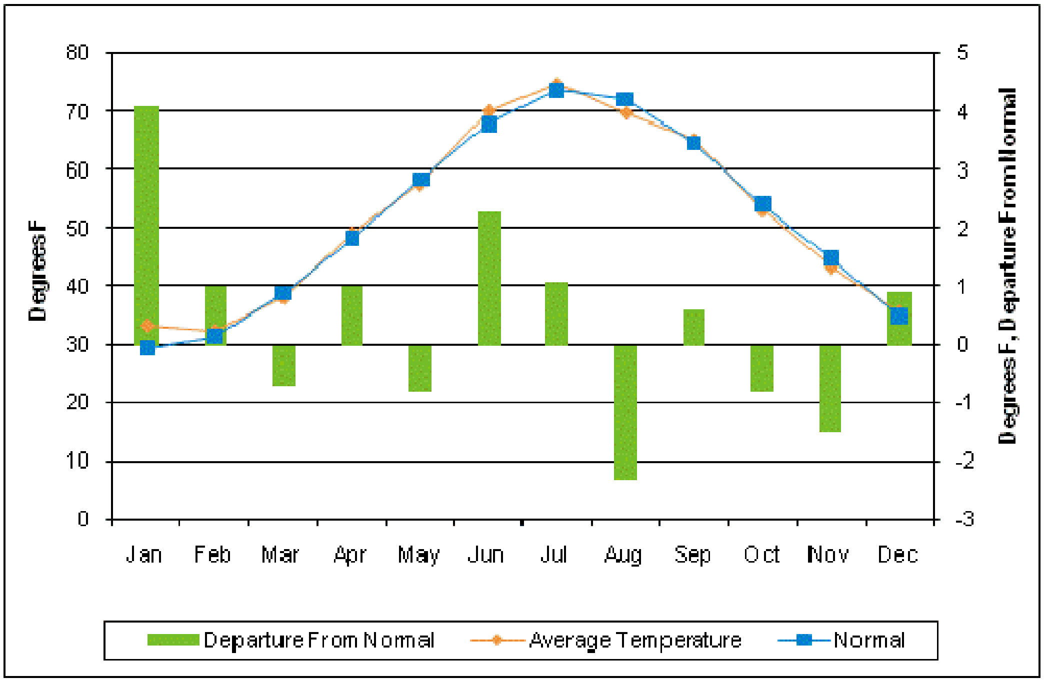

Figure 3-11: Ambient air temperature compared with normal values and the departure from normal, 2008.

Figure 3-12 and Figure 3-13 show historical load factors for New England expressed as a percentage for weather-normalized and actual load levels, respectively.[99] Figure 3-12 shows the long-term trend of a declining load factor in New England, while Figure 3-13 demonstrates that in a given year, load factors shift up and down based on weather. 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. Load factors are important to the electricity markets because they indicate the amount of capacity that must be maintained year-round to meet the high loads that may only last for a few hours during the year.

[99] 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.

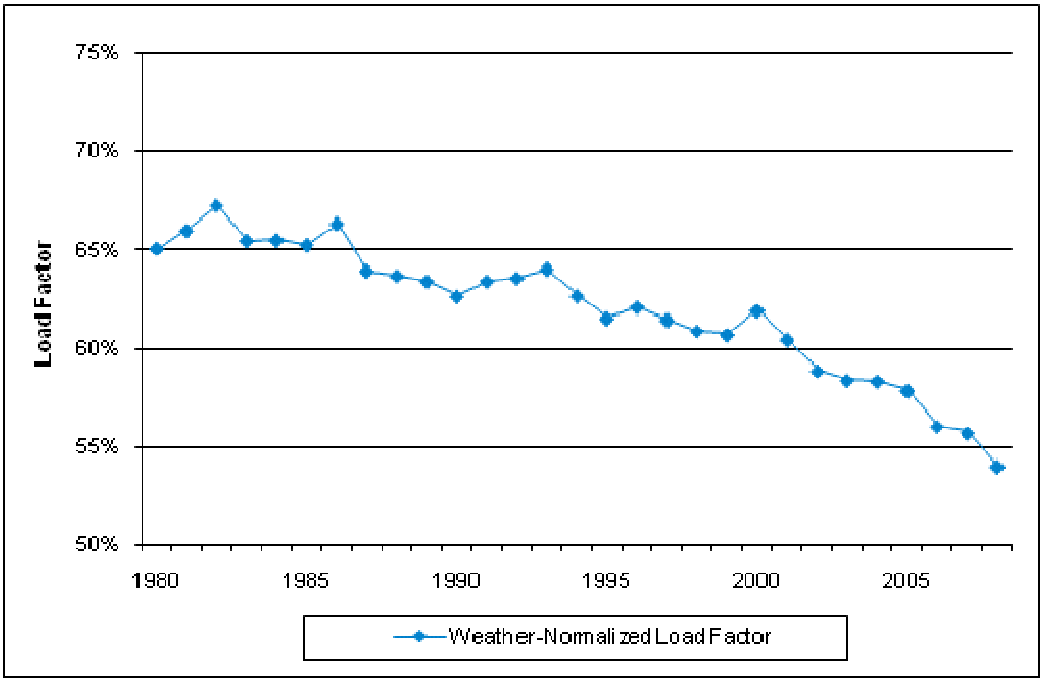

Figure 3-12: New England summer-peak load factors, weather-normalized load, 1980 to 2008.

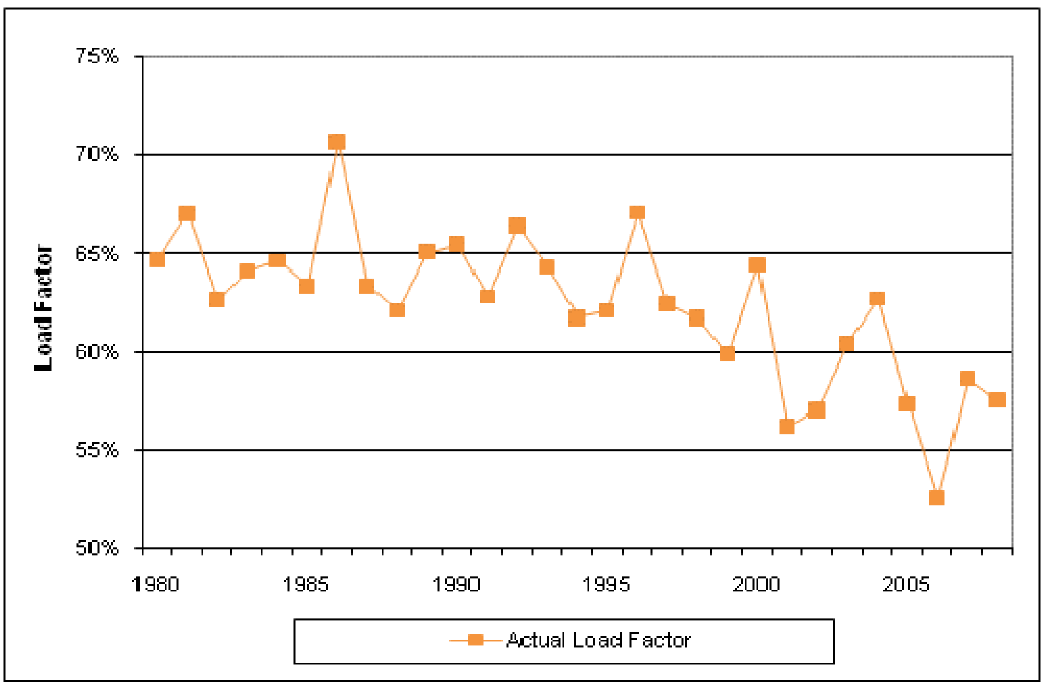

Figure 3-13: New England summer-peak load factors, actual load, 1980 to 2008.

Over the past few decades, weather-normalized load factors have fallen significantly, dropping from 65% in 1980 to 54% in 2008. From 2007 to 2008, weather-normalized NEL decreased, while weather-normalized peak demand increased, continuing the trend of a decreasing load factor. Forecasts of higher peak growth and lower energy use mean that load factors may continue to decline.

However, this trend may change as demand participates more actively in the capacity market, as discussed in Section 3.5.

3.3.6 Real-Time Supply

This section presents data on real-time summer capacity, generation by fuel type, and self-scheduled generation. The results from a marginal unit analysis also are included.

3.3.6.1 Summer Capacity

Figure 3-14 shows summer capacity (MW) by fuel type for 2008.[100] In 2008, dual-fueled generators capable of burning either oil or natural gas made up 24% of installed capacity, while natural-gas-fired generators made up 25% of installed capacity. Many dual-fueled generators capable of burning either oil or natural gas operate primarily on natural gas. In most cases, environmental restrictions on emissions from burning oil limit the total number of hours per year a generator can operate on oil.

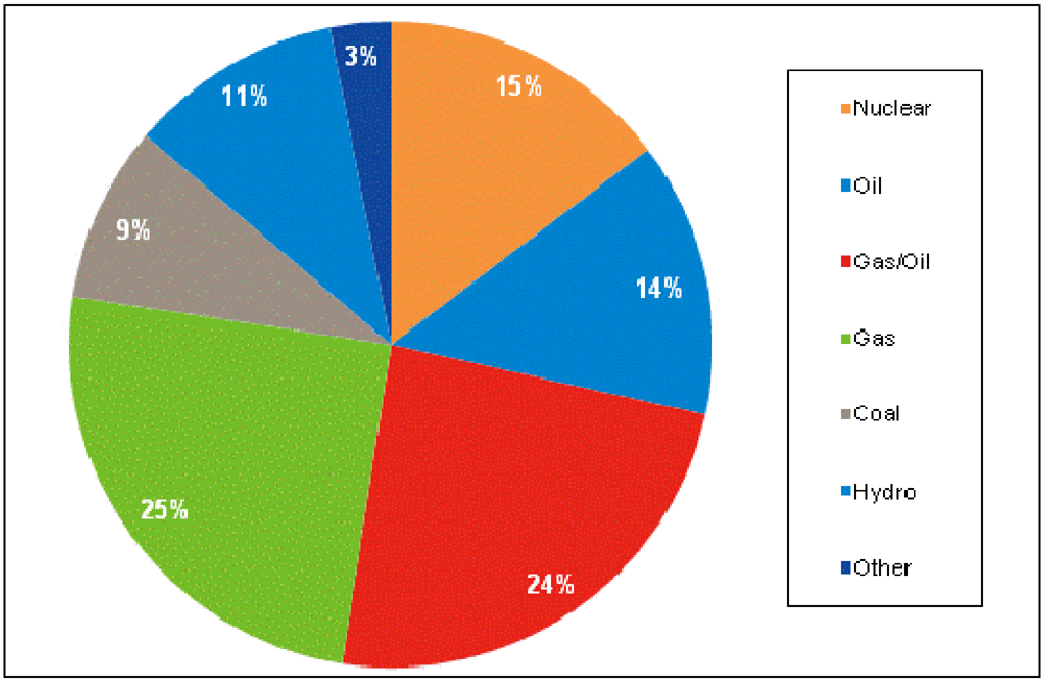

Figure 3-14: System summer capacity by fuel type, 2008.

The total 2008 generation claimed for capability is 31,088 MW, up 191 MW from the 2007 level of 30,897 MW. These values represent actual conditions as of the summer peaks. The 191 MW increase is the result of new generation, existing generation reratings, or "behind-the-meter" generation.[101] By comparison, 44 MW of new generation were added to the system in 2007, no new generation resources were added in 2006, and 92 MW of new generation were added in 2005.

[100] Detailed information about generating capacity is available in the ISO's forecast reports of capacity, energy, loads, and transmission. See http://www.iso-ne.com/trans/celt/report/index.html.

[101] *Behind-the-meter* generation is connected to the power grid at an electrical location that is on the load side of the metering facility that connects to the transmission system controlled by the ISO. Output from a behind-the-meter generator reduces the amount of electric energy that needs to be withdrawn from the ISO-controlled network.

3.3.6.2 Generation by Fuel Type

Figure 3-15 shows actual generation by fuel type as a percentage of total generation for 2007 and 2008. 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 shown later in Figure 3-18 and Figure 3-19 (see Section 3.3.6.4). The percentage of total electric energy generated by gas-fired and gas- and oil-fired plants in New England was 41% in 2008. Nationwide, about 20% of electric energy is produced by power plants fueled by natural gas.[102]

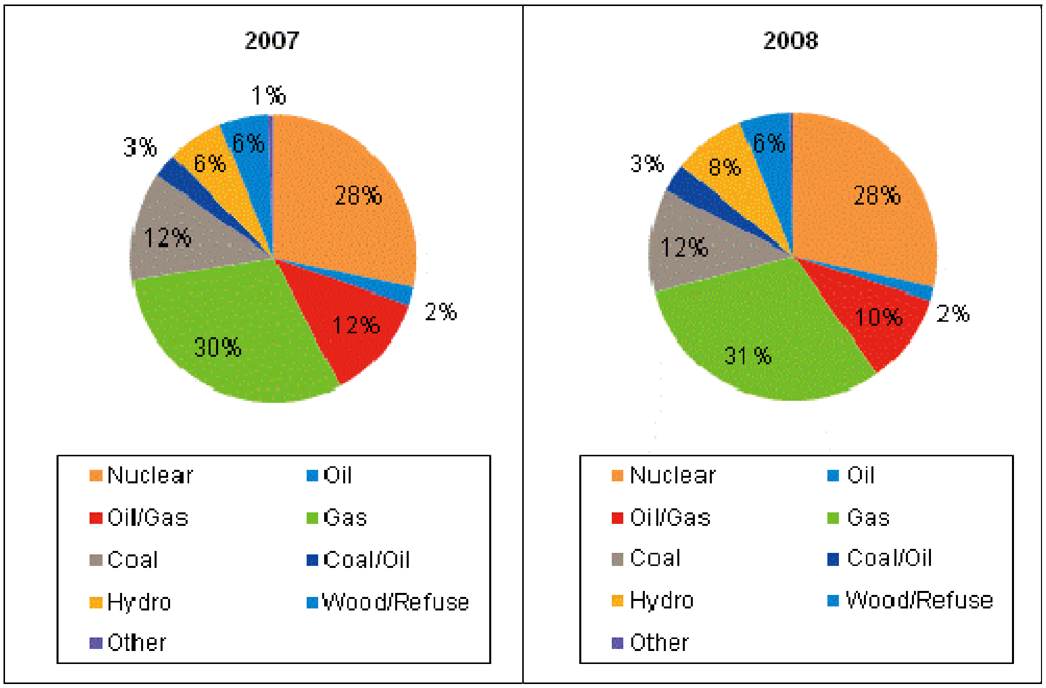

Figure 3-15: New England generation by fuel type, 2007 and 2008.

3.3.6.3 Self-Scheduled Generation

Figure 3-16 shows real-time self-scheduled generation as a percentage of total electric energy produced from 2006 through 2008. 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 the output of their generators 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 bilateral contracts to provide energy or 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 2008, self-scheduled generation averaged 70% of total real-time energy, up from 63% in 2007.

[102] Energy Information Administration, *Electricity Generation* (Washington, DC: U.S. DOE, September 2008); available at http://www.eia.doe.gov/neic/infosheets/electricgeneration.html (accessed March 31, 2009).

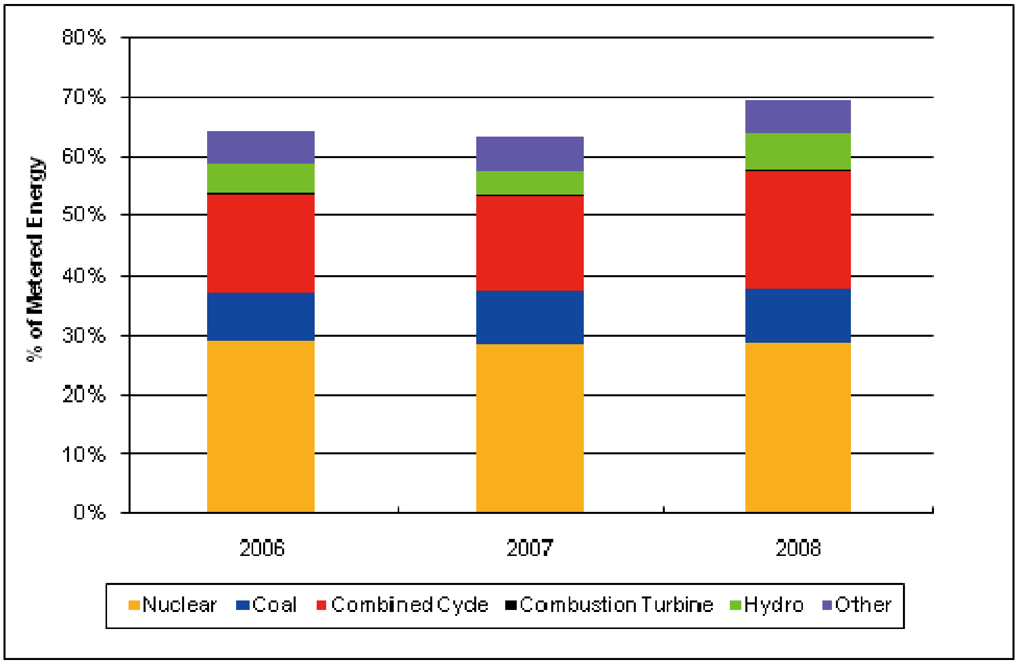

Figure 3-16: Total real-time self-scheduled electric energy as a percentage of total metered energy, 2006 to 2008.

Figure 3-17 shows real-time generation that was self-scheduled, separated by fuel type, as a percentage of each fuel type's total metered electric energy. Nuclear generators always self-schedule their generation; therefore, 100% of the metered energy generated by all nuclear plants is self-scheduled energy. All other generator categories self-scheduled a higher percentage of their energy in 2008 than in 2007.

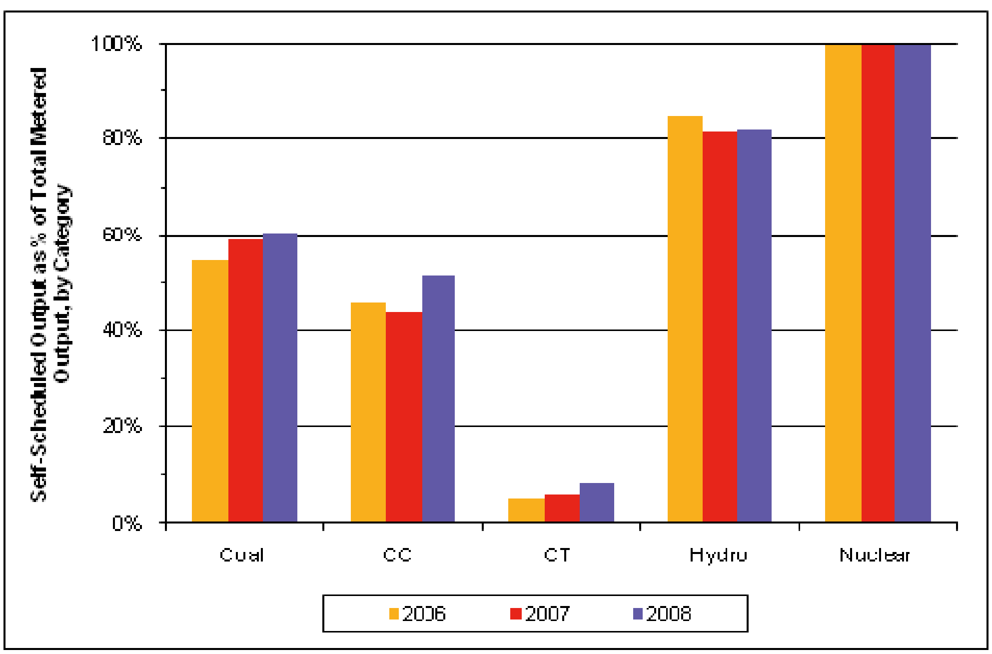

Figure 3-17: Total real-time self-scheduled electric energy as a percentage of metered energy by fuel type, 2006 to 2008.

Note: CC refers to combined-cycle units; CT refers to combustion turbines.

3.3.6.4 Marginal Unit Analysis

Because the price of electricity changes as the price of the marginal fuel changes, analyzing marginal units by fuel type helps explain changes in electricity prices. The system has one marginal unit that is classified as the *unconstrained* marginal unit during all pricing intervals. In a locational marginal pricing market, however, more than one marginal unit exists when transmission constraints are present. For example, during high load levels, the interface between Connecticut and the rest of the New England power system could become constrained, and generation in Connecticut would need to be *dispatched up* to meet load. For some transmission-constraint conditions, the ISO lowers the output of a marginal unit.

Figure 3-18 and Figure 3-19 show the percentage of total pricing intervals during which each input fuel was marginal during 2008. Figure 3-18 includes only the unconstrained units, while Figure 3-19 shows the constrained-up and constrained-down resources.[103] When combining both unconstrained periods shown in Figure 3-18 and constrained periods shown in Figure 3-19, the marginal fuel type during more than 62% of the pricing intervals is natural gas. The next most frequent fuels on the margin are coal and pumped storage functioning as asset-related demand. These two fuel types are generally marginal during the overnight hours.

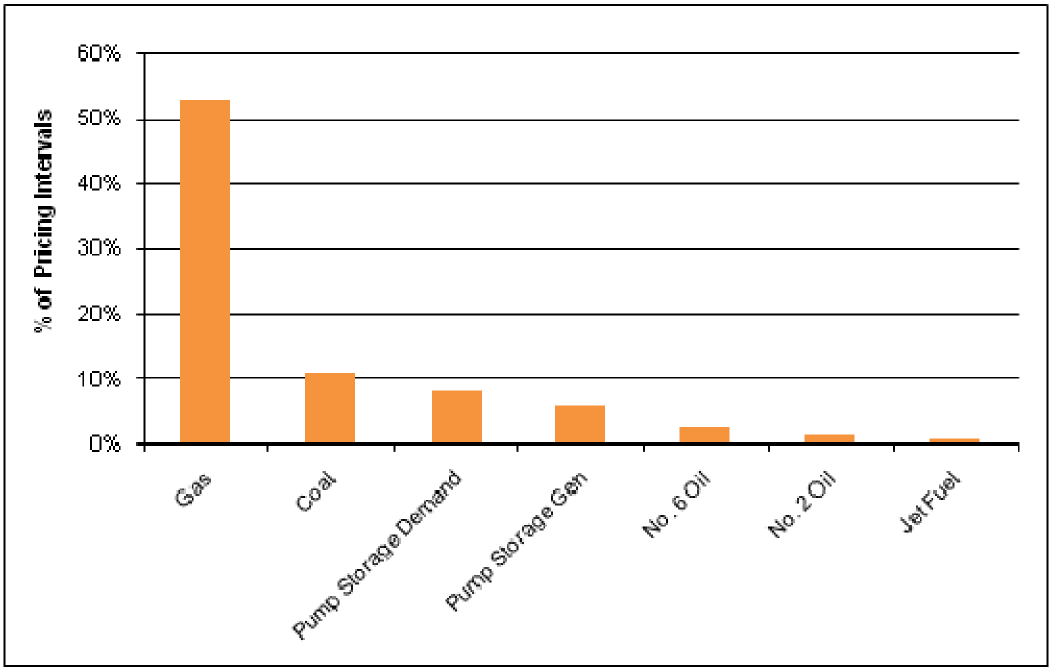

Figure 3-18: Marginal fuel-mix percentages of unconstrained pricing interval, 2008.

Note: The figure includes each marginal unit; when the system has more than one marginal unit at the same time, the marginal minutes are distributed equally across the marginal units' fuel types.

[103] *Constrained-up* resources operate at a higher output level than they otherwise would because of a transmission constraint. *Constrained-down* resources operate at a lower output level due to transmission constraints.

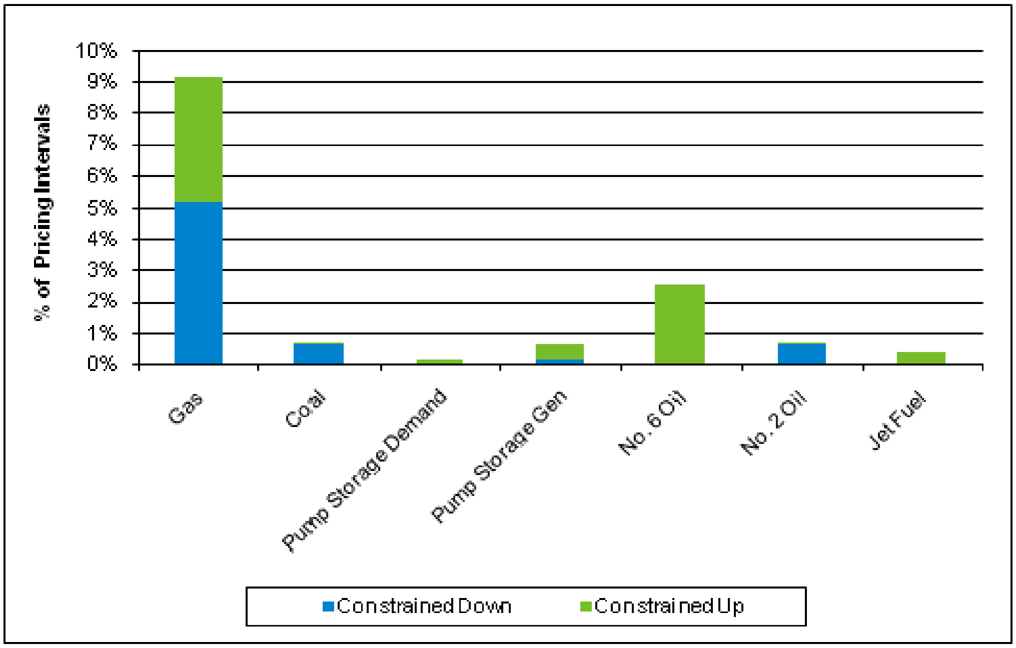

Figure 3-19: Constrained intervals as a percentage of all pricing intervals by marginal fuel type, 2008.

Note: The figure includes each marginal unit; when the system has more than one marginal unit at the same time, the marginal minutes are distributed equally across the marginal units' fuel types.

3.3.7 Net Interchange with Neighboring Regions

During 2008, New England remained an overall net importer of power; with net imports from Canada exceeding net exports to New York. As Figure 3-20 shows, net interchange with neighboring balancing authority areas totaled 9,311 GWh for 2008, a 54.3% increase from 2007. Figure 3-21 shows imports and exports by interface. Average metered flow by hour for all external interfaces can be found in the appendix, Section 8.1.

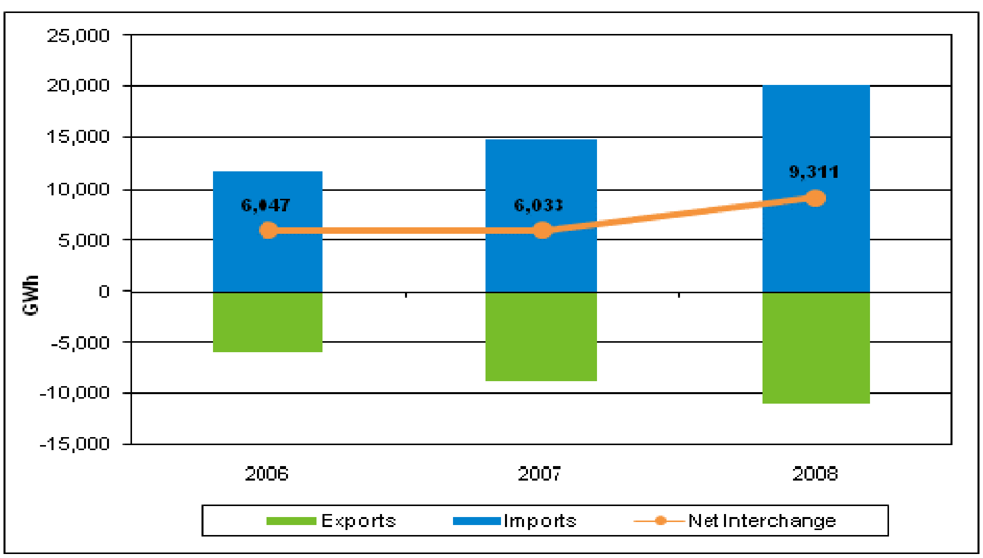

Figure 3-20: Scheduled imports and exports and net external energy flow, 2006 to 2008.

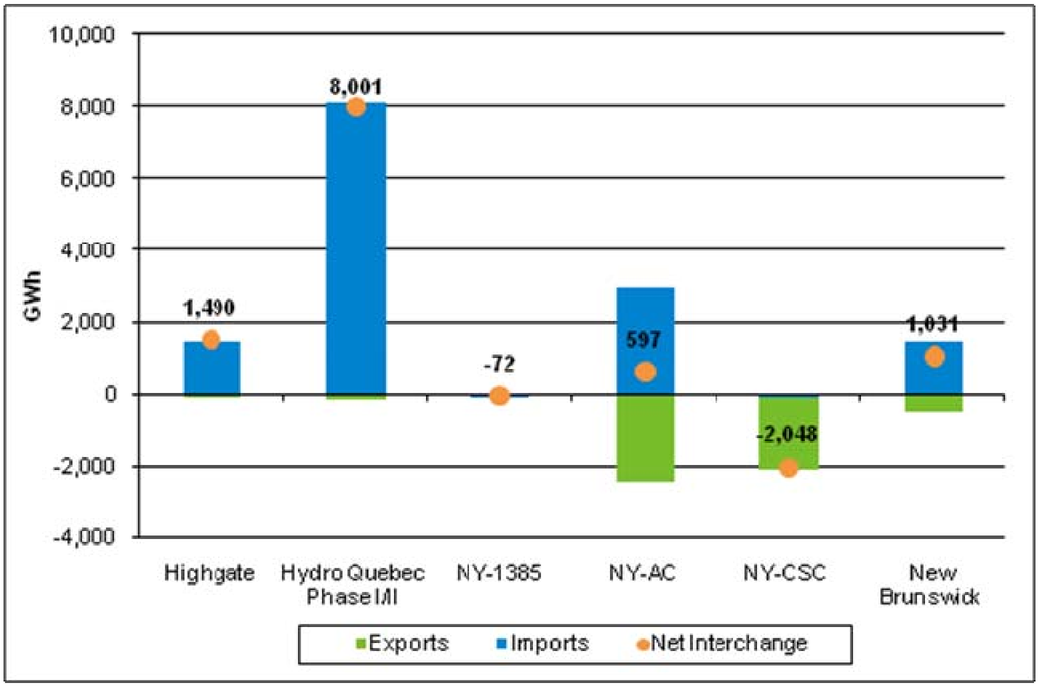

Figure 3-21: Imports and exports by interface, 2008.

3.3.8 Generating-Unit Availability

Table 3-8 reports the annual Weighted Equivalent Availability Factors (WEAF) of New England generating units for 1999 to 2008.[104] As shown, the availability of generators has been increasing in general from a low in 1997 to a new high of 90% in 2007, dropping to 86% in 2008.

[104] 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 3-8
New England System Weighted Equivalent Availability Factors, %[(a)]

	1997	1998	1999[(b)]	2000	2001	2002	2003	2004	2005	2006	2007	2008
System average	78	81	81	81	89	88	88	88	89	89	90	86
Fossil steam[(c)]	*n/a*	*n/a*	79	78	84	85	87	86	86	88	87	85
Coal	*n/a*	*n/a*	*n/a*	*n/a*	88	84	84	83	88	84	87	81
Coal/oil	*n/a*	*n/a*	*n/a*	*n/a*	86	74	84	88	88	85	79	90
Oil	*n/a*	*n/a*	*n/a*	*n/a*	84	86	84	84	84	89	84	80
Gas/oil	*n/a*	*n/a*	*n/a*	*n/a*	80	84	91	87	84	91	89	89
Wood/refuse	*n/a*	*n/a*	*n/a*	*n/a*	95	94	94	93	93	93	92	92
Nuclear	*n/a*	*n/a*	82	89	91	91	91	94	89	93	92	90
Jet engine	*n/a*	*n/a*	70	88	92	94	94	97	95	96	97	95
Combustion turbine	*n/a*	*n/a*	90	83	89	93	93	97	95	95	94	90
Combined cycle	*n/a*	*n/a*	83	80	84	90	85	86	86	84	86	83
Pre-1999 combined cycle	*n/a*	*n/a*	91	89	94	92	91	92	92	92	92	92
New (installed 1999–2004) combined cycle	*n/a*	*n/a*	47	67	76	90	84	84	86	81	83	80
Hydro	*n/a*	*n/a*	81	81	95	96	95	94	94	96	96	97
Pumped storage	*n/a*	*n/a*	86	86	93	87	92	90	92	91	98	93
Diesel	*n/a*	*n/a*	88	88	98	98	98	95	98	99	97	98

(a) The statistics for 1997 to April 1999 were calculated from the NEPOOL Automated Billing System (NABS). NABS data are representative of traditional, cost-based system dispatch. The system captured actual run-time MW/hr data and outage information as defined in the billing rules. The NEPOOL Settlements Department primarily used the data for payment to the generators. Using statistical analysis approved by the NEPOOL Power Supply Planning Committee, generators were allotted a certain number of maintenance outage weeks per year to perform scheduled maintenance. Outages that exceeded this or took units out of service any other time were considered unplanned or forced outages. Statistics for May 1999 to 2005 were based on competitive bid-based dispatch and were calculated from a Short-Term Outage Database. The ISO Operations Department populates this database using information it receives from generators; it records scheduled and unplanned outages as they occur in real time.

(b) Data are represented for May through December 1999.

(c) Beginning in 2003, the ISO began separating the "fossil-steam" category into the five categories as noted. In this context, "n/a" stands for "not calculated."

Figure 3-22 illustrates that the spring and fall months continue to have the greatest number of outages, while the summer period has the least. This figure shows monthly average outages in megawatts and the average amount of capacity on outages as a percentage of total available seasonal claimed capability (SCC), as well as the average number of megawatts that were unplanned outages.[105] The figure shows how the system reacts to electrical peak demands. Less capacity is on outage during periods of high demand (summer- and winter-peak periods) than during the spring and fall low-

[105] Seasonal claimed capability is the maximum generation capacity of a resource as demonstrated during a seasonal audit.

demand periods. While outages are higher in spring and fall, most of the outages are planned and usually are due to units needing annual maintenance.

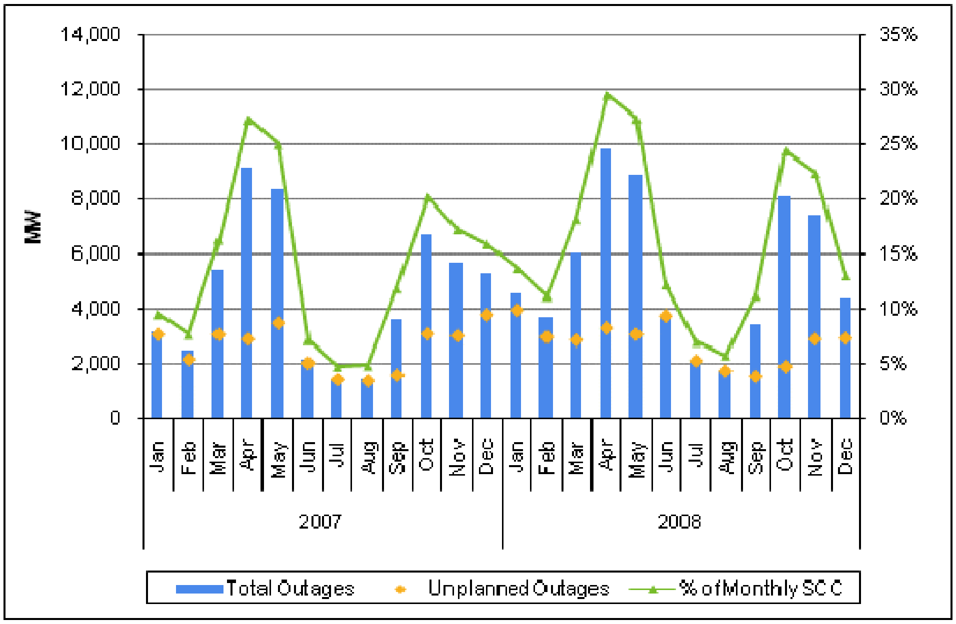

Figure 3-22: Generator-unit average monthly outages as percentage of SCC, unplanned outages, 2008.

Figure 3-23 illustrates how the availability of the New England generating units tracks monthly demand. Specifically, Figure 3-23 shows the monthly WEAF and the monthly peak demand as a percentage of the annual peak demand. Similar to the information presented in Figure 3-22, the average availability for New England generating units is lowest during the months that have the lowest peak demand. When New England experiences the highest peak demand, the average availability of New England generators is the greatest.

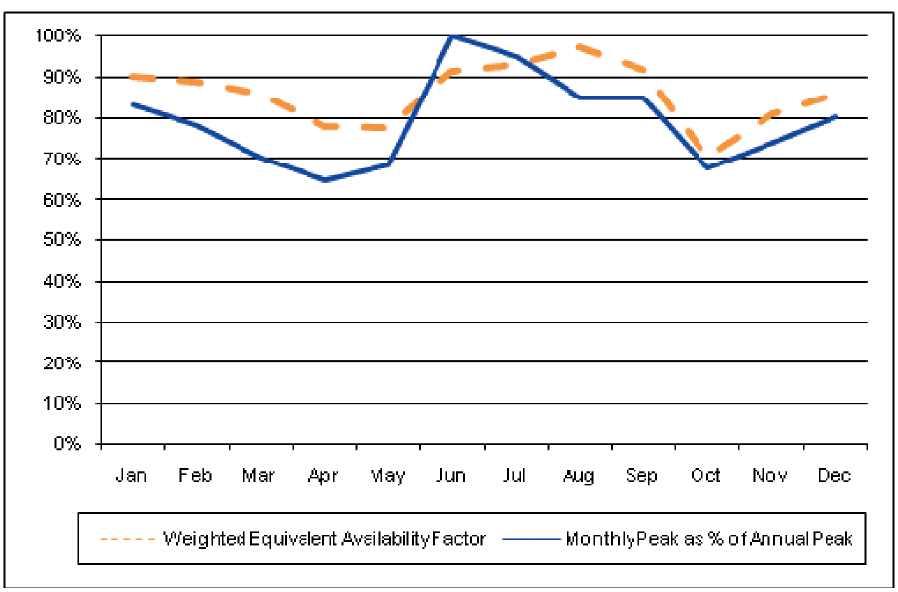

Figure 3-23: Monthly peak demand and monthly average availability (WEAF)

3.4 Congestion Revenue and Financial Transmission Rights

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

3.4.1 Congestion Revenue

Figure 3-24 shows total congestion revenue by month from 2006 through 2008. Total congestion revenue increased 8% from 2007 to 2008, rising from $112 million to $121 million. Day-ahead congestion revenue decreased by 4%, so the increase in total congestion revenue for the year was the result of much less negative real-time congestion revenue (negative $17.7 million in 2007 compared with negative $4.3 million in 2008). The amount of negative real-time congestion revenue was a major cause of the monthly underfunding of FTRs during 2007. Improvements in coordinating outage scheduling and in evaluating day-ahead and real-time transmission limits contributed to the large decrease in negative real-time congestion revenue.

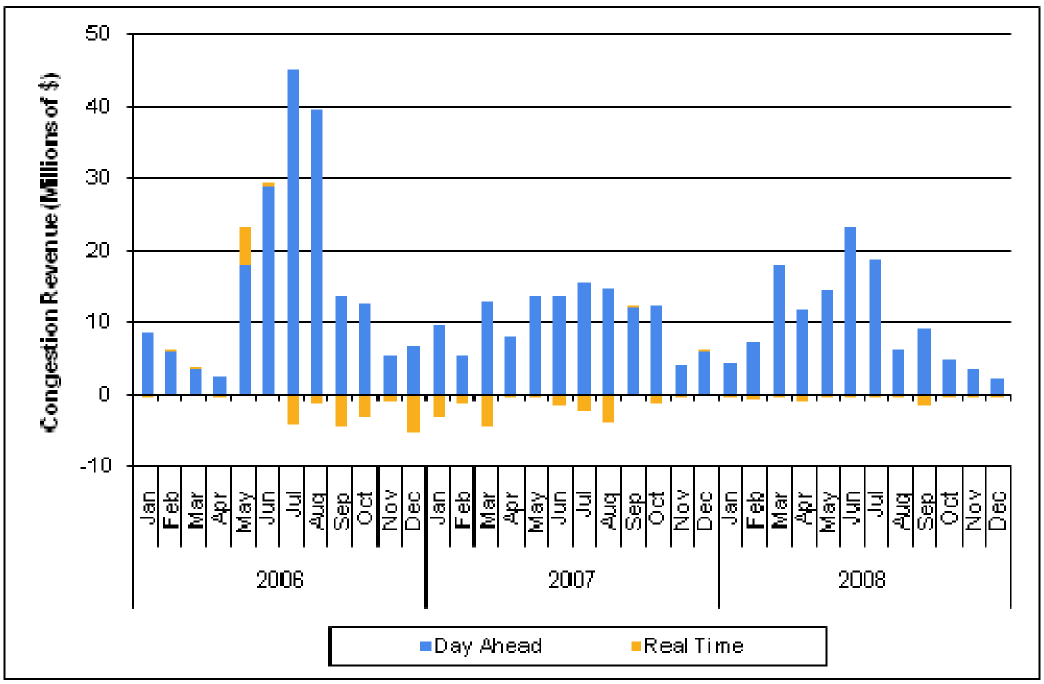

Figure 3-24: Day-ahead and real-time congestion revenue by month, 2006 to 2008.

3.4.2 Financial Transmission Rights and Auction Revenue Rights

The ISO conducts the 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*.

3.4.2.1 FTR Auction Results

The annual auction for FTRs covering the 2008 calendar year was held in December 2007 and offered 50% of the system's transmission capacity. FTR auctions also were held for each month in 2008. In each of the monthly auctions, the remaining balance of the transmission system capacity, accounting for expected outages within that month, is made available.[106] The number of participants bidding in each auction ranged from 29 participants in the annual auction to 41 participants in the September 2008 auction. The auction revenues from the 12 monthly auctions and the single 12-month auction covering 2008 totaled $117 million.

Figure 3-25 shows the awarded FTR megawatts and auction revenues for the annual auctions held in 2006, 2007, and 2008. Relative to 2007 and 2008, the total auction revenue was high in 2006. This is consistent with the uncertainty in fuel prices resulting from the Gulf Coast hurricanes in 2005.[107] The amount of annual awarded megawatts has been increasing from 2006 to 2008. The increase is due to the combined effect of new participants to the annual auction for FTRs and the increased participation by entities that acquired FTRs.

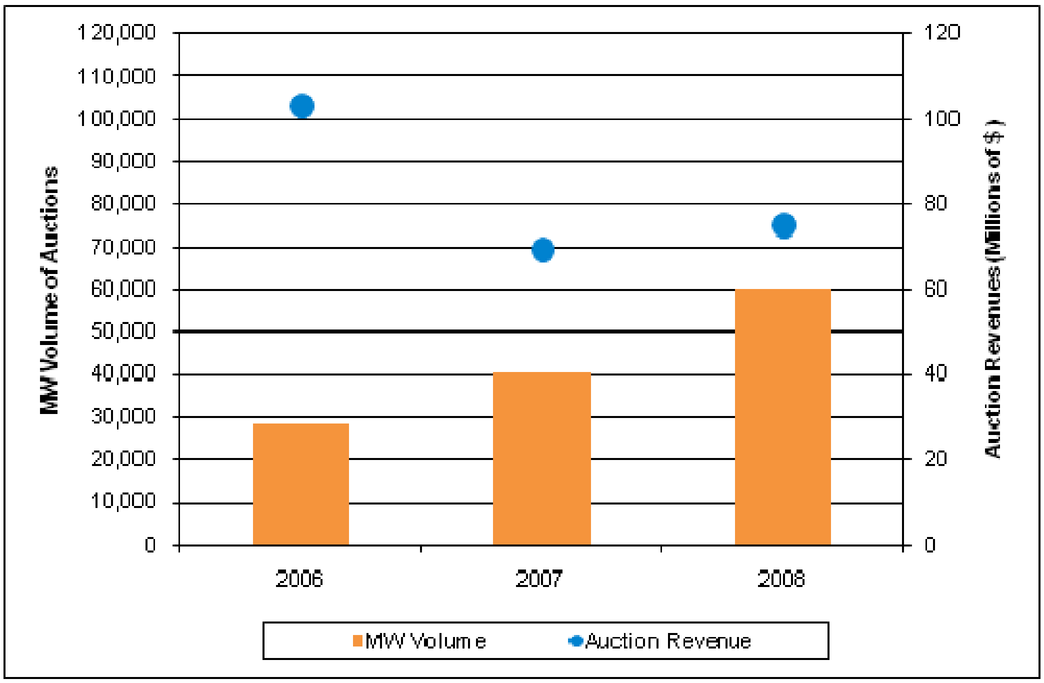

Figure 3-25: Annual auction volumes and auction revenues, 2006 to 2008.

Figure 3-26 shows the total cleared volume and auction revenues from the monthly auctions. All three years show a similar pattern of higher revenues in the summer months.

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

[107] The 2006 annual FTR auction was held in December 2005, when the eventual impact of the fall 2005 hurricanes on oil and natural gas production was still uncertain.

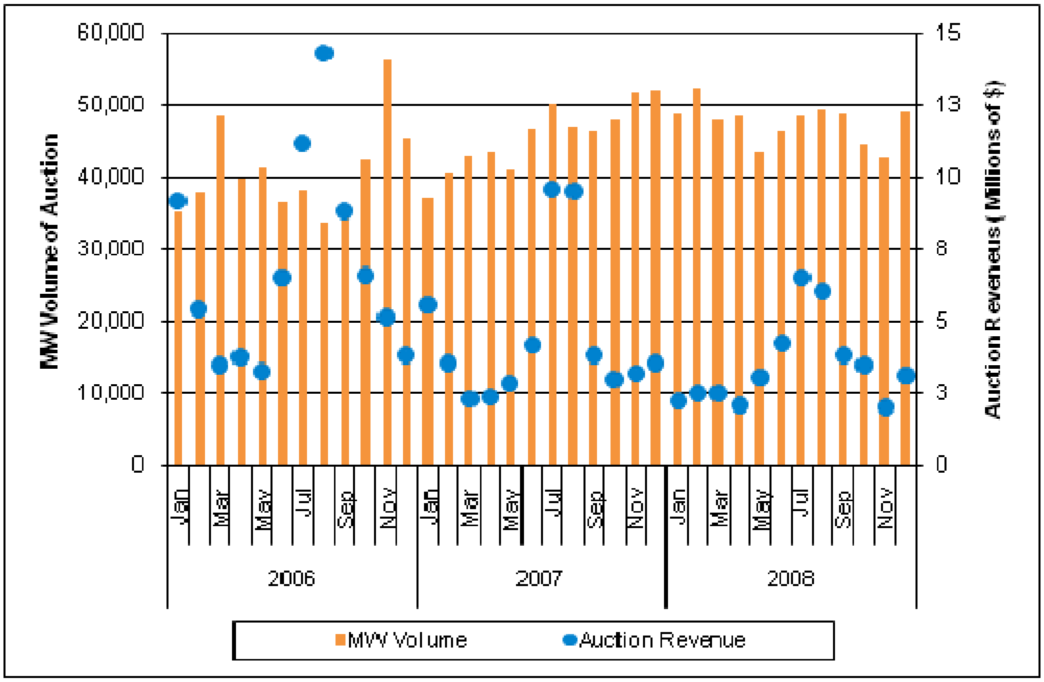

Figure 3-26: Volumes and total values of monthly auctions, 2006 to 2008.

Table 3-9 shows the total distribution of auction revenue for 2006 through 2008 for qualified upgrade awards and the three auction revenue right categories. The largest portion of auction revenue was returned to load-share ARR holders. The distribution of revenue to QUAs increased both in terms of the percentage of the auction revenue and total dollars.

Table 3-9
Total Auction Revenue Distribution 2006 through 2008, $

Type of Revenue	2006	2007	2008
QUA dollars	3,029,487	3,343,390	7,997,938
Excepted transaction dollars[(a)]	278,913	267,209	137,592
NEMA contract dollars	5,215,541	465,603	207,897
Load-share dollars	176,471,802	118,735,550	108,387,117
Total auction revenue	184,995,744	122,811,752	116,730,543

(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 *Open Access Transmission Tariff* (OATT), Section II.40, and for the time periods described in therein. These transactions can be found in the OATT, Attachments G, G-1 and G-3; http://www.iso-ne.com/regulatory/tariff/index.html.

Figure 3-27 shows the distribution of ARR dollars (load share, NEMA contract, and excepted transactions) by load zone for 2007 and 2008. The process for allocating these auction revenues is based on the FTR auction prices and is defined in detail in *Market Rule 1*. Connecticut continued to receive the largest amount of load share dollars; however, the total percentage distributed to Connecticut decreased, and the percentage to SEMA increased. This was caused by higher FTR auction prices in the SEMA load zone in response to ongoing day-ahead congestion in SEMA. The pattern of distributions to the remaining load zones remained relatively constant.

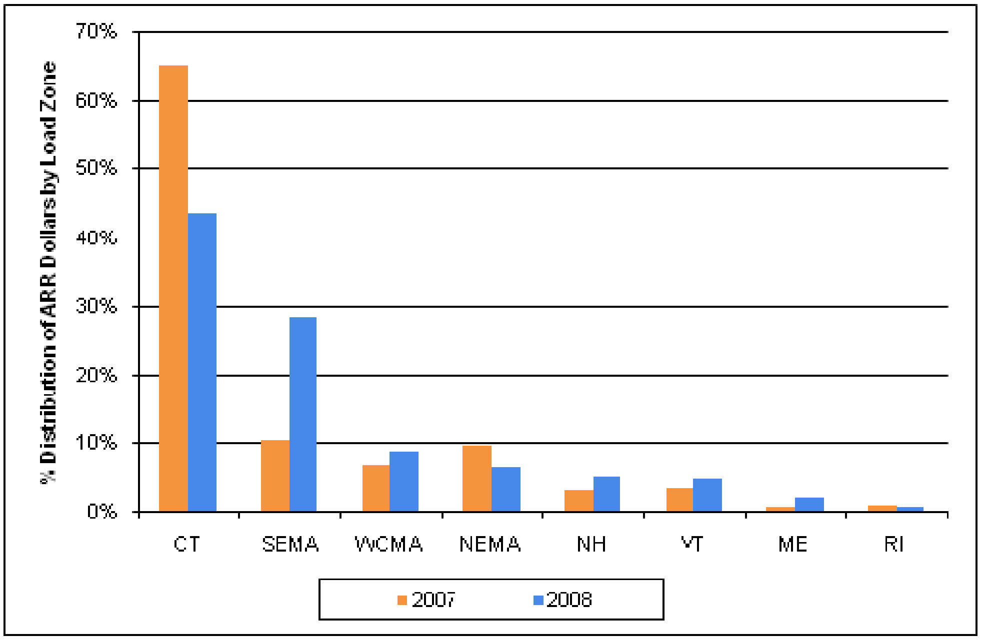

Figure 3-27: Change in load share ARR distribution by load zone.

3.4.2.2 FTR Performance as a Hedging Instrument

The performance metric of an FTR as a hedge against expected day-ahead congestion costs is the percentage of full FTR funding after year-end FTR surpluses are distributed. The metric shows whether the FTR provides the congestion cost certainty (i.e., the full funding) the participant is expecting. This section examines whether FTRs are meeting that objective.

Table 3-10 summarizes the monthly Congestion Revenue Balancing Fund for 2008, including the monthly percentage of positive target allocations paid to FTR holders.[108] During nine of the 12 months in 2008, FTR holders were paid their full positive target allocations. During 2008, the CRBF did not experience the large and frequent shortfalls that existed during the latter part of 2006 and throughout 2007. During 2008, the surpluses from the months with surpluses were more than sufficient to repay the shortfall amounts plus interest during the year-end settlement. An excess of $18 million was distributed back to market participants or transmission customers in proportion to their total yearly net congestion costs paid.

[108] The full accounting of the CRBF is available at http://www.iso-ne.com/markets/othrmkts_data/conrev_summ/2009/2009_ftr_monthly_summary.pdf.

Table 3-10
Monthly CRBF, $, 2008

Month	Day-Ahead Congestion Revenue	Real-Time Congestion Revenue	Negative Target Allocation Collected (Paid by Participants)	Positive Target Allocation (Owed to Participants)	Actual Positive Allocations Paid to Participants	Surplus or Shortfall	Percent of Positive Target Allocation Paid
Jan	4,442,672	−102,254	3,487,922	6,670,302	6,670,302	1,163,697	100%
Feb	7,461,783	−546,661	4,278,698	11,388,921	11,185,619	−203,302	98%
Mar	18,162,129	−315,081	3,639,768	16,530,708	16,530,708	4,954,336	100%
Apr	12,030,178	−754,256	5,708,416	17,098,318	17,002,864	−95,454	99%
May	14,718,961	−144,092	8,793,909	23,484,496	23,379,891	−104,606	100%
Jun	23,453,199	-296,216	10,392,397	31,732,442	31,732,442	1,816,849	100%
Jul	18,865,836	−50,205	8,006,777	20,251,467	20,251,467	6,574,343	100%
Aug	6,443,611	−215,953	4,391,866	9,042,302	9,042,302	1,588,615	100%
Sep	9,072,431	−1,314,610	6,707,193	14,343,343	14,343,343	122,626	100%
Oct	4,878,972	−327,631	2,451,875	6,673,243	6,673,243	332,374	100%
Nov	3,679,929	−162,884	1,511,953	4,047,063	4,047,063	980,349	100%
Dec	2,148,487	−89,882	1,514,472	4,125,604	3,573,626	−551,979	87%

3.4.2.3 FTR Performance as a Financial Instrument

If the FTR market were competitive and efficient, the expected profit for those using it as a financial instrument would be $0. This is measured by the path profitability of FTRs. Path profitability equals the cost of acquiring the FTR (auction cost) minus the revenue generated by the FTR, which is based on the differences between the day-ahead congestion components.

Figure 3-28 and Figure 3-29 show the monthly customer-based net profit levels for on-peak and off-peak FTRs for 2008. All FTR paths held by a participant during the year are included in the analysis. In both figures, individual columns represent a profit range of $10. The gray sections highlight the range of a loss of $50 to a profit of $50. The distributions of monthly customer path profitability generally are centered close to zero but are skewed slightly to the negative as indicated by the average values of negative $191.75/month for on-peak FTRs and negative $26.73/month for off-peak FTRs. A different perspective of these customer path averages is that the average monthly path profit was a loss of $0.05/MWh for an on-peak FTR path and a loss of $0.02/MWh for an off-peak FTR path. These results generally are consistent with a competitive market in which the expected profits of a risk neutral participant holding an FTR as an arbitrage instrument approaches $0.

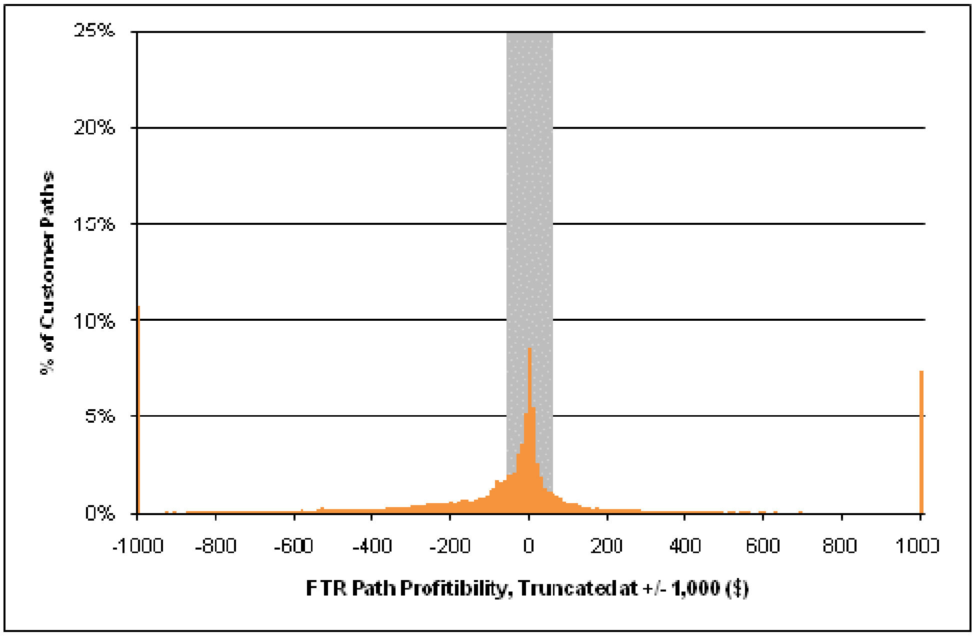

Figure 3-28: Profitability of on-peak FTRs held through to settlements, 2008.

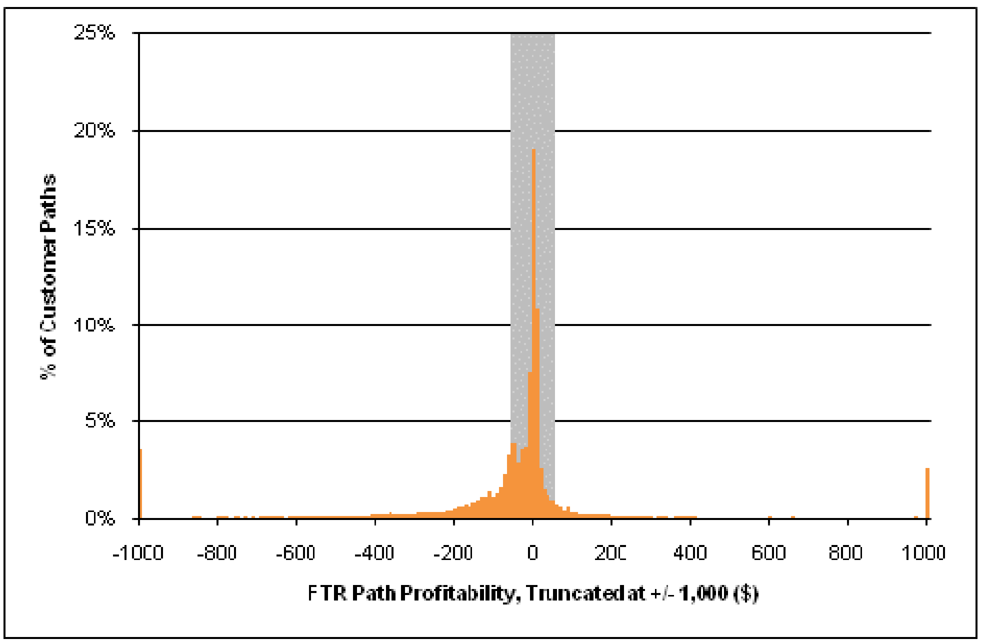

Figure 3-29: Profitability of off-peak FTRs held through to settlements, 2008.

3.4.3 Financial Transmission Rights Conclusions

The annual and monthly FTR auctions conducted in 2008 generally were competitive and resulted in a total of $117 million in auction revenues. This revenue was distributed to congestion-paying LSEs and transmission customers that have supported the transmission system. The majority of the revenue was distributed as auction revenue rights. The distribution of auction revenue rights varied from previous years. The Connecticut load zone received the largest portion of load share ARRs. However, because of increased congestion components in the SEMA load zone, this load zone received a larger share of the auction revenue than has been the case historically.

FTRs effectively provided the hedge against day-ahead congestion costs that FTRs were intended to provide. During nine of 12 months, 100% of positive target allocations were paid to holders of FTRs. In the remaining three months, the shortfalls were small as a percentage of the target allocations. The surpluses during the nine months with a surplus were more than large enough to offset the shortage months, meaning that over the year, FTRs hedged all congestion costs. FTRs are a financial instrument and can be used to arbitrage auction results and actual day-ahead congestion. A review of the results of the profitability of FTR paths shows that the profit is close to zero, indicating an efficient and competitive market.

This is a notable improvement compared with the results from 2007, when negative real-time congestion revenues resulted in a monthly shortfall in eight of the 12 months. The improvements in the hedging performance of FTRs (percentage of positive target allocations actually distributed) is attributable to improvements in the evaluation of the day-ahead and real-time transmission limits and revisions implemented to Operating Procedure 3 (OP 3), *Transmission Outage Scheduling*, which improved the coordination of outage scheduling.[109]

3.5 Demand Resources

Price sensitivity to the quantity of a product purchased is an important aspect of efficient markets. However, current technological, political, and cultural challenges must be overcome to fully incorporate price-sensitive demand into real-time wholesale electricity markets. As an interim, second-best alternative, the ISO has implemented programs to allow demand resources to participate in the current wholesale electricity markets.

3.5.1 Demand-Resource Program Participation

The number of megawatts of demand resources participating in ISO markets has increased noticeably during the past three years. Total enrollment in demand-resource programs increased approximately 28% during 2008, increasing from a December 2007 total of 1,978.1 MW to 2,536 MW in December 2008. Between January 2005 and December 2008, the total increase has been 2,149.5 MW, or an increase of 556%. Figure 3-30 shows demand-response and ODR program enrollments by quarter for 2005 through 2008. The ODR programs, which did not exist until December 2006, account for a significant portion of the growth in demand resources over the past two years.

[109] ISO New England's Operating Procedure 3 is available at html.http://www.iso-ne.com/rules_proceds/operating/isone/op3/index.html.

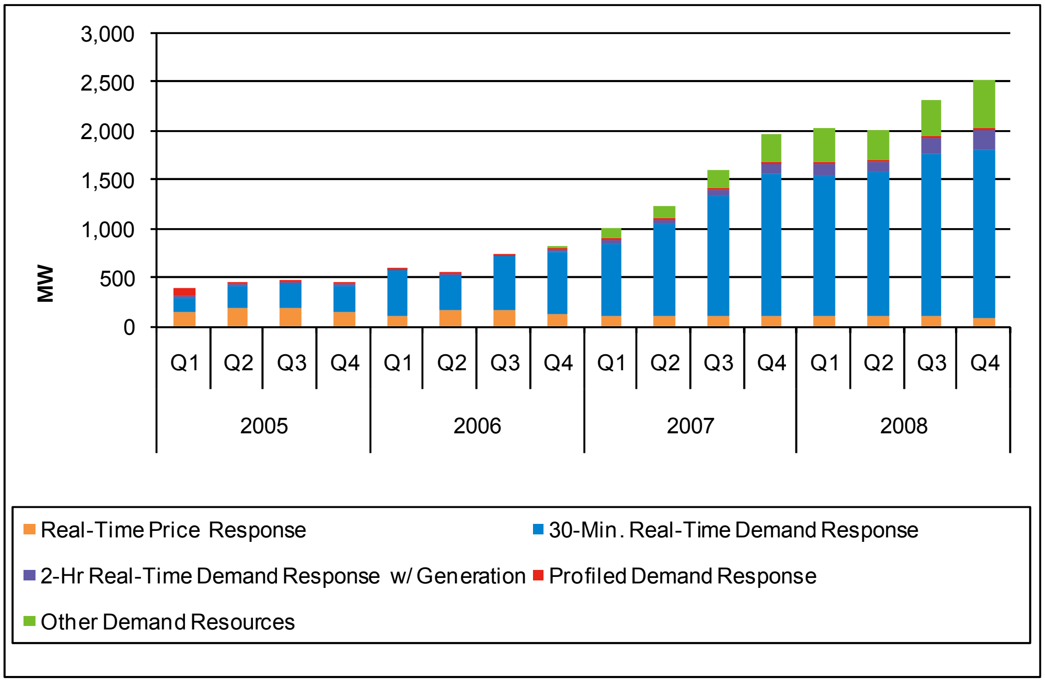

Figure 3-30: Quarterly demand-resource enrollments, 2005 through 2008.

Note: Refer to Section 2.7 for a description of these programs.

Most of the increases have been in the Real-Time 30-Minute Demand-Response Program. This program is activated either in OP 4, Action 9 (implement a Power Watch) or in Action 12 (implement a voltage reduction). Customers selecting Action 12 activation can anticipate fewer hours of interruptions. Currently, 59.4% of the customers in this program have elected Action 12 as their activation trigger.

All programs, except the Real-Time Price Response Program, have grown since 2007. Increased capacity transition payments are the most likely explanation for the sizable increase in demand-response program participation over the past two years because all the demand-response programs, except the price-response program, qualify as capacity and thus are eligible for capacity transition payments. The increase in enrollments coincides with the start of the capacity transition payments in December 2006. The FCM settlement established a scheduled transition payment rate that increases over time. From the beginning of the transition period through May 2008, the transition payment rate had been \$3.05/kW-month, and it increased as scheduled to \$3.75/kW-month in June 2008. Before the capacity transition payments, capacity payments through the installed capacity supply auction averaged \$0.21/kW-month.[110] Table 3-11 shows a state-by-state breakdown of demand-response assets and megawatts of participation during December 2008.

[110] See the ISO's *2006 Annual Markets Report* available at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html.

Table 3-11
Demand-Response Assets by State, December 2008

State	# of Assets	Total MW	Percent of Total	Real-Time Price Response (MW)	Real-Time 30-Min Demand Response (MW)	Real-Time 2-Hour Demand Response (MW)	Profiled Demand Response (MW)
CT	1,498	744.7	37	7.3	737.4	-	-
VT	110	87.9	4	2.9	66.2	12.9	5.9
MA	1,108	492.9	24	55.0	394.9	42.8	-
RI	227	94.7	5	16.4	71.7	6.6	-
NH	148	119.8	6	4.5	112.1	3.1	-
ME	89	489.1	24	-	346.0	132.1	11
Total	**3,180**	**2,029.1**	**100%**	**86.1**	**1,728.30**	**197.5**	**16.9**

Participation increased across all states throughout the year. Table 3-12 shows the increase in demand-response program enrollments by state from December 2007 to December 2008 along with the percentage change. Maine stands out as an area that generally is not congested and has lower energy prices than other zones but has added significant demand-response capacity, at 84.1 MW or 25% of the total 2008 increase. Table 3-11 shows that Maine has 489 MW, or 24% of the regionwide total of 2,029 MW. This is due to the participation of several large industrial customers.

Table 3-12
Demand-Response Program Enrollment Changes, by State, December 2007 to December 2008

Change 2007 to 2008							
State	Assets	Total MW	Real-Time Price Response (MW)	Real-Time 30-Min. Demand Response (MW)	Real-Time 2-Hr. Demand Response (MW)	Profiled Demand Response (MW)	State MW Change as % of Regionwide Change
CT	152	2.7	0	2.7	0	0	0.01%
ME	37	84.1	0	27.6	56.5	0	25.0%
MA	281	159.8	−8.5	148.1	20	0	48.0%
NH	77	45.1	0	43.7	1.4	0	13.4%
RI	32	18.4	−0.1	16.8	1.6	0	5.5%
VT	53	25.3	−3.4	27.1	7	0	8.0%
Total	**632**	**335.4**	**−12**	**294.5**	**86.5**	**0**	**100%**
Regionwide % change from 2007	**25%**	**20%**	**−12%**	**18%**	**70%**	**0%**	

3.5.2 Southwest Connecticut "Gap" Request for Proposals

On December 1, 2003, the ISO issued a request for proposals (RFP) soliciting up to 300 MW of temporary supply and demand resources for Southwest Connecticut for 2004 through 2008 (SWCT "Gap" RFP).[111] The stated goal of the RFP was to improve the reliability of the bulk electric power system in Southwest Connecticut. The average monthly enrollment from January 2008 to the end of the program in May 2008 was 135 MW. Most of the resources selected under this RFP are participating in the 30-Minute Real-Time Demand-Response Program. Resources enrolled in the SWCT Gap RFP received supplemental capacity payments totaling $126 million over the four-year contract term.

3.5.3 Demand-Response Interruptions

The ISO demand-resource programs involve a combination of reductions in load from the bulk grid with different triggers and obligations categorized into demand-response programs and "other demand resources" (refer to Section 2.7). The demand-response programs produce interruptions when the ISO initiates an event for the particular program, while interruptions from ODRs are measured during prespecified periods. This section describes the megawatt-hour interruptions and payments made during 2008.

3.5.3.1 Summary of Interruptions

Load interruptions occur when an ISO-initiated event is activated or when a participant in the Day-Ahead Load-Response Program, whose day-ahead load-interruption offer was accepted, meets or exceeds its obligation to interrupt load in real time. As described in Section 3.5.3.4, a Real-Time Price-Response Program event is activated when a forecasted real-time price exceeds $100/MWh. A reliability event is activated when OP 4 Action 3, 9, or 12 is called at the zonal or systemwide level.

The Real-Time Price-Response Program was activated a total of 207 days out of a possible 256 nonholiday weekdays during 2008. The DALRP produced interruptions on 103 days in 2008, down from 249 days in 2007. Table 3-13 lists the number of days with an interruption by program type. During 215 of 256 event-eligible days of the year, at least one of the demand-response programs experienced interruptions. A total of 111,717 MWh of load were interrupted during the year from all demand-response programs. The reasons for the high frequency of interruptions are described in more detail in Section 3.5.3.3 and Section 3.5.3.4. The 30-Minute Demand-Response Program was activated once, on May 8, 2008. The activation took place in NEMA when OP 4 Action 9 was declared. The days with interruptions include audits that are required by the market rule.

[111] Additional information on the ISO's request for proposals for Southwest Connecticut Emergency Capability can be found in the *Final Report on Evaluation and Selection of Resources in SWCT RFP for Emergency Capability 2004–2008* (October 4, 2004), available at http://www.iso-ne.com/genrtion_resrcs/reports/rmr/swct_gap_rfp_fnl_rpt_10-05-04.doc.

Table 3-13
Number of Interruption Days in 2008

Demand-Response Program	Number of Days with Interruptions
Real-Time 30-Minute Program with emergency generation	3
Real-Time 30-Minute Program without emergency generation	4
Real-Time Two-Hour Program	2
Real-Time Profiled Program	2
Real-Time Price-Response Program	207
Day-Ahead Load-Response Program	103

Table 3-14 details the total payments made to demand-resource programs in 2008. Payments for all demand-resource programs totaled $90.9 million in 2008. The majority of this total was paid to reliability programs as transition payments. Payments for the Real-Time Price-Response Program, which was activated almost every nonholiday weekday, totaled $5.1 million (almost $5/kW-month) despite enrollments of only 86.1 MW as of December 2008.

Table 3-14
All-In Cost of Demand Response, 2008

Demand-Response Program	Payment
Total payments made to Day-Ahead Load-Response Program	$6,736,662
Total payments for Real-Time Price-Response Program	$5,134,406
Total payments to reliability programs for real-time events/audits	$1,425,272
Total transition payments made to reliability programs	$77,627,856
Grand Total	**$90,924,196**

3.5.3.2 Other Demand Resources

Figure 3-31 summarizes the load reductions provided by ODRs throughout 2008. As Figure 3-31 shows, most monthly ODR reductions come from energy-efficiency projects. ODRs have lower winter ratings than summer ratings, which accounts for the lower performances from January through March and again in December. Unlike other resources, capacity for ODRs is measured by monthly energy reductions.

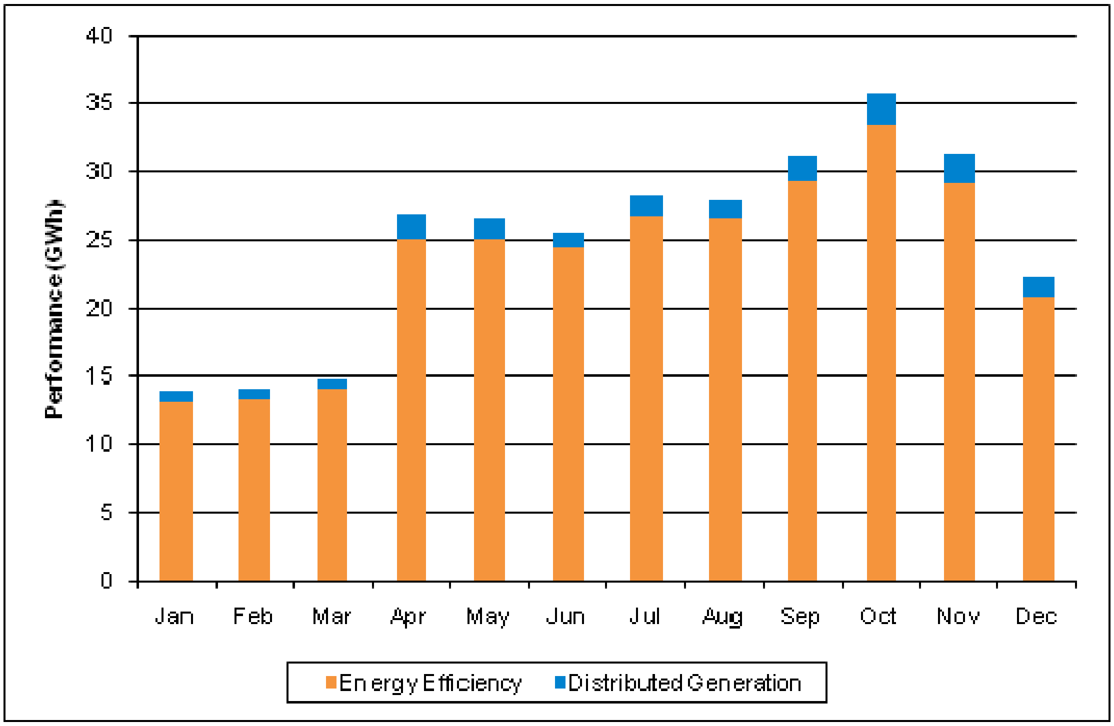

Figure 3-31: Estimated monthly energy reductions from ODRs, by resource type, 2008.

3.5.3.3 Analysis of Day-Ahead Load-Response Program Interruptions

Table 3-15 compares DALRP interruptions with the day-ahead cleared megawatt-hours and whether the resource was in a real-time reliability program or in the Real-Time Price-Response Program.[112] In the table, real-time deviations from the day-ahead cleared quantities ("Day-Ahead Cleared") are counted as part of real-time interruptions ("Actual Interruptions Produced by Day-Ahead Program Resources in Real Time").

[112] Participation in either the Real-Time Price-Response Program or one of the real-time reliability programs is a prerequisite to enrollment in the DALRP. Resources enrolled in a reliability program that participate in the DALRP are doing so based on a price and megawatt offer. This is considered a price-based interruption, unless a reliability situation occurs in real time and OP 4 actions are called.

Table 3-15
Day-Ahead Load-Response Program Interruptions and Payments, 2008

	Reliability Program Resources			Real-Time Price-Response Resources		
	Column A	Column B	Column C	Column A	Column B	Column C
	Day-Ahead Cleared (MWh)[(a)]	Actual Interruptions Produced by Day-Ahead Program Resources in Real Time (MWh)[(a)]	Day-Ahead Program Payments ($)[(a)]	Day-Ahead Cleared (MWh)[(a)]	Actual Interruptions Produced by Day-Ahead Program Resources in Real Time (MWh)[(a)]	Day-Ahead Program Payments ($)[(a)]
Jan	10,083.70	43,293.21	$3,935,335.35	48.40	313.24	$30,979.85
Feb	2,473.40	9,549.39	$749,694.19	12.70	77.58	$6,185.99
Mar	16.80	19.05	$2,847.67	-	-	-
Apr	14.40	68.77	$10,256.96	-	-	-
May	327.40	1,921.44	$368,109.70	6.50	9.00	$1,465.95
Jun	246.20	2,488.74	$460,136.28	9.00	59.74	$11,909.51
Jul	826.00	4,942.83	$834,431.86	25.90	167.00	$26,123.82
Aug	74.80	213.90	$23,253.42	1.50	0.00	$18.57
Sep	49.80	534.79	$50,342.19	1.90	3.48	$325.98
Oct	-	-	-	-	-	-
Nov	309.60	1,171.33	$95,997.46	8.80	38.06	$2,895.86
Dec	205.20	1,296.08	$125,124.24	4.50	14.21	$1,228.06
Total	**14,627.30**	**65,499.53**	**$6,655,529.32**	**119.20**	**682.31**	**$81,133.59**

(a) The day-ahead program payments [column C] are equal to the sum of two components—day-ahead cleared megawatt payments and real-time deviation payments:

Day-ahead cleared MW payments = day-ahead cleared MWh [column A] × day-ahead LMP.

Real-time deviation payments = real-time deviation MWh [column B – column A] × real-time LMP.

If the ISO activates a demand-response program, any megawatts in excess of the day-ahead cleared quantity interrupted by a resource in real time are counted as real-time interruptions and would not be included as a day-ahead program interruption.

In 2008, a total of 14,746 MWh of demand response cleared in the day-ahead market; resources in the reliability programs provided the most response (14,627 MWh), while resources in the Real-Time Price-Response Program that cleared day-ahead provided the remaining 119 MWh. These day-ahead cleared megawatt-hours represent only 22% of the total of 66,181 MWh that the DALRP counted as interruptions (the sum over the year of the day-ahead cleared megawatt-hours and day-ahead deviation megawatt-hours). DALRP payments for deviations amounted to $5.3 million in 2008, down from $14.1 million in 2007. Total DALRP payments have decreased from about $17 million in 2007 to $6.7 million in 2008.

In 2008, the ISO identified a problem with the DALRP. The core issue was that the minimum offer level of $50/MWh, combined with substantial increases in fuel costs, facilitated bidding and related behavior that permitted DALRP participants to exaggerate load reductions from their demand-response assets. This behavior resulted in payments for nonexistent load reductions.

The bidding behavior arose from the interplay between the level of the minimum offer price in the DALRP and the manner of calculating the customer baseline (CB), which is the estimated level of "normal" consumption during the time period used to determine load reductions. The ISO uses a rolling 10-day average of a customer's load during days without load-response events. Because participants were clearing in the day-ahead market almost every day, CBs became static, and customers were able to freeze their baselines at relatively high levels.

On February 5, 2008, the ISO filed changes to the DALRP design to address the problems associated with strategic bidding behavior that created and maintained static CBs.[113] The ISO's solution was to redefine the minimum bid price from a fixed level of $50/MWh to a formulaic level calculated as a heat rate multiplied by a monthly fuel index.[114] A 12.92 MMBtu/MWh heat rate was implied from the previous minimum offer price of $50/MWh and the average fuel prices from 2002, the year in which the DALRP was designed. This resulted in enrolled resources clearing day ahead during fewer days. This in turn resulted in more accurate CBs because on days when a participant's asset does not clear, its actual load for that day is incorporated into the 10-day rolling average that calculates the going-forward CB. The combination of the rule change to the minimum bid price and the resulting, more accurate CBs resulted in DALRP participation and interruptions that are more consistent with the program's design objectives.

The revised minimum bid price has reduced the frequency that resources bidding at the minimum offer price clear in the day-ahead load-response process. Since February 2008, the total amount of day-ahead cleared megawatts has decreased significantly, reaffirming that the revision to the minimum offer price succeeded in refreshing static baselines and more accurately reflecting load-reduction by DALRP participants.

Figure 3-32 shows the total DALRP interruptions in both 2007 and 2008. In January 2008, the month before the filing, interruptions totaled close to 45 GWh. In February, interruptions dropped to about 10 GWh and have remained at or below 5 GWh for the remainder of the year.

[113] *Filing of Changes to Day-Ahead Load-Response Program*, FERC Docket ER08-538 (February 5, 2008).

[114] A generator's *heat rate*, traditionally reported in Btu/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.

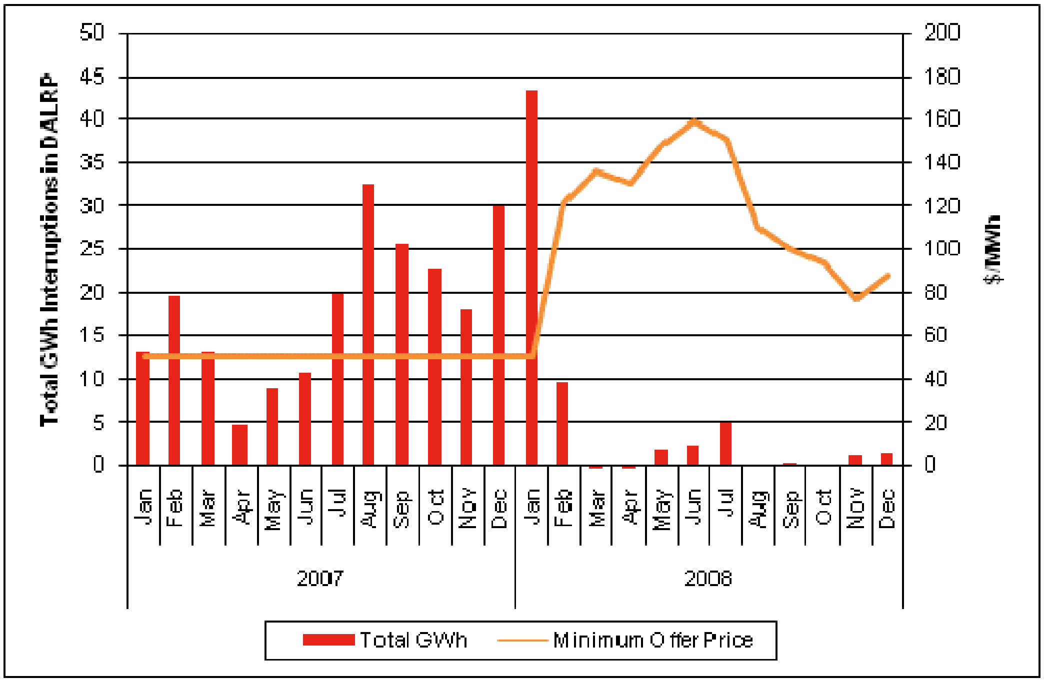

Figure 3-32: **Total interruptions for the DALRP per month, 2007 to 2008**.

During January and February 2008, most of the interruptions were day-ahead deviations. After the rule change was implemented, most of the interruption megawatt-hours were from the Real-Time Price-Response Program. Figure 3-33 compares the demand-response interruptions in 2008 that are attributable to the DALRP with those attributable to the other programs. It further breaks down the DALRP interruptions into "Day-Ahead Cleared" and "Day-Ahead Deviation" megawatt-hours.

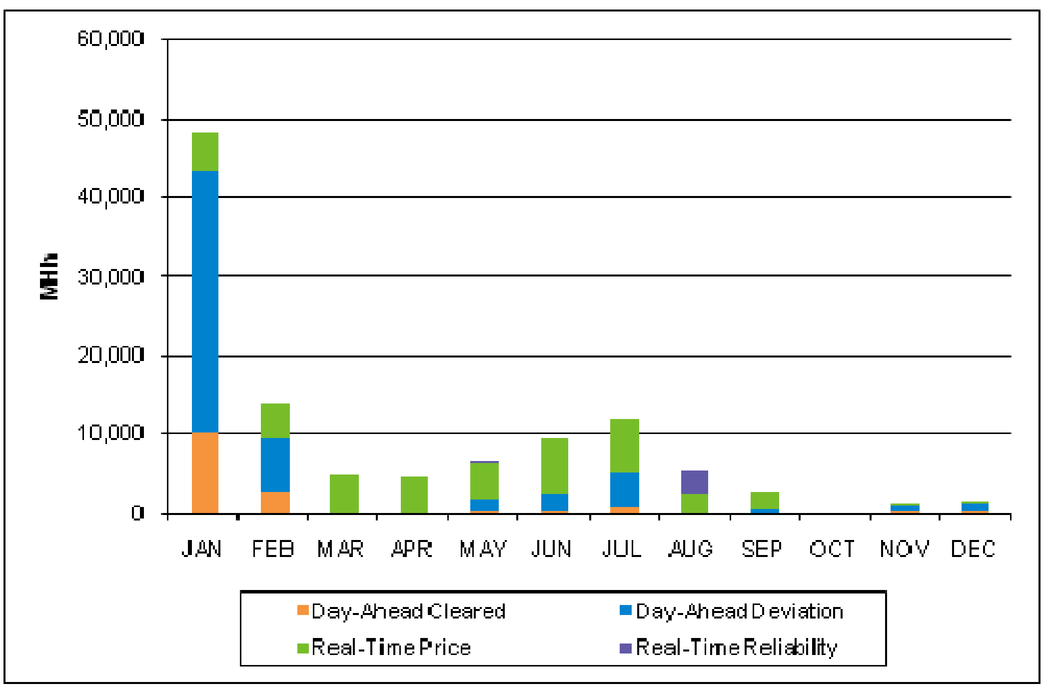

Figure 3-33: Load-reduction program type, MWh, 2008.

The number of assets participating in the DALRP increased in 2008, despite the increase in the minimum offer price. Figure 3-34 shows that participation in the DALRP grew during 2007 and 2008. By December 2007, slightly more than 80 assets on average were offering into the DALRP, compared with just over 10 assets at the beginning of the year. By December 2008, the number grew to just over 140 assets. The increasing number of assets participating in the program, however, did not translate into a higher quantity of cleared megawatts.

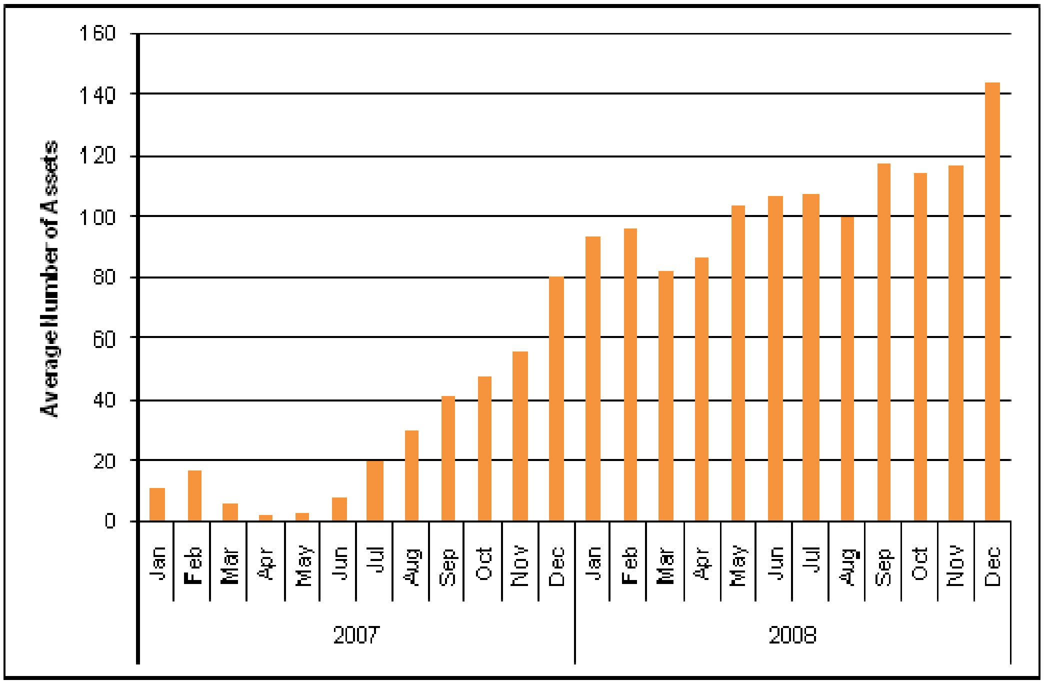

Figure 3-34: Number of assets participating in the DALRP, 2007 and 2008.

One DALRP issue the FERC filing did not address directly concerned payments made to participants for deviations from the quantities cleared in the day-ahead market. Participants in the Day-Ahead Load-Response Program can offer in the minimum quantity of 100 kWh but are compensated for the total amount of reductions. Deviations from the cleared day-ahead quantity are paid the real-time LMP. These deviations constituted the bulk of the payments for the DALRP in 2007. While the revised minimum bid price was successful in reducing the frequency in which DALRP assets were clearing in day-ahead, the minimum offer amount remains at 100 kWh and offers no disincentive for curtailing more than the cleared amount.

The greatest deviations that have occurred since the FERC filing were in May, June, and July 2008 on days when the real-time LMPs were relatively high for the year (in some cases, reaching as high as $400/MWh). These assets were responding to price signals, and extra curtailments during these high-priced hours were needed. However, operators must know how many megawatts of interruptions demand resources will provide to manage a reliable system efficiently, and predicting the megawatt quantity of interruptions that will be provided is difficult during any given interruption event.

Figure 3-35 shows the total day-ahead cleared megawatt-hours and the deviation megawatt-hours for 2007 to 2008. In February 2008, deviations were reduced because fewer assets were clearing in the day-ahead market. The deviations resurfaced in the summer months of May, June, and July, when LMPs began to increase and assets cleared more frequently in the day-ahead market.

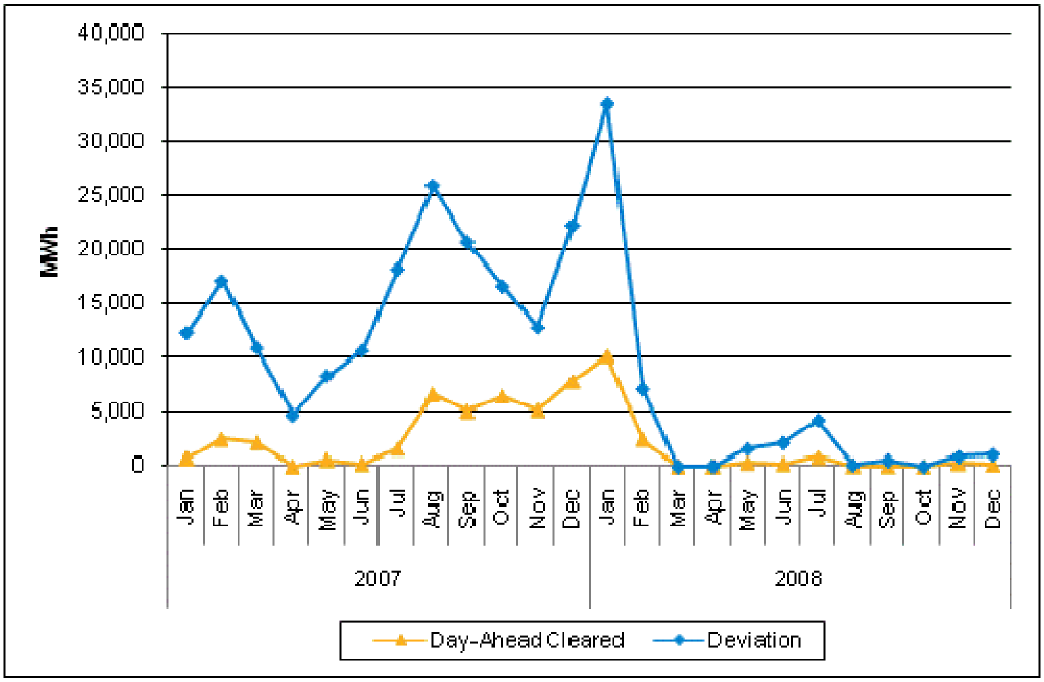

Figure 3-35: Total day-ahead cleared MWh and deviations in the DALRP per month, 2007 to 2008.

3.5.3.4 Real-Time Load-Response Program Interruptions

Voluntary participation in price-response program events depends on the electric energy price levels and the business condition for each customer. The Real-Time Price-Response Program experienced the most activity in 2008 and had a total of 207 days with interruptions and a total of 42,528 MWh of load curtailments. The number of resources that curtailed load and the total load curtailed varied from event to event. Table 3-16 shows the interruptions (MWh) and payments associated with the real-time load-response programs in 2008.[115]

[115] Payments and interruptions for resources that are deviations from a day-ahead cleared megawatt quantity are counted as part of the real-time program when the ISO activates an event in the resources' load zone.

Table 3-16
Real-Time Load-Response Program Interruptions and Payments, 2008

	Reliability Programs					Price-Response Program	
	Demand Response		Profiled Response		FCM Transition Payments		
	Real-Time Program Interruptions (MWh)	Real-Time Program Payments ($)[(a)]	Real-Time Program Interruptions (MWh)	Real-Time Program Payments ($)[(a)]	Total Transition Payments ($)[(a)]	Real-Time Program Interruptions (MWh)	Real-Time Program Payments ($)[(a)]
Jan	-	-	-	-	$5,786,318.47	4,763.58	$544,734.80
Feb	-	-	-	-	$5,788,514.16	4,478.77	$466,486.98
Mar	-	-	-	-	$6,001,827.78	4,840.05	$496,727.37
Apr	-	-	-	-	$5,919,353.99	4,652.42	$534,246.64
May	89.62	$44,809.00	-	-	$6,035,496.71	4,535.17	$570,809.76
Jun	-	-	-	-	$5,838,543.48	6,948.36	$943,002.52
Jul	-	-	-	-	$5,806,521.66	7,057.01	$1,036,889.07
Aug	2,891.22	$1,380,463.55	26.70	$10.00	$5,290,905.31	2,170.11	$226,066.33
Sep	-	-	-	-	$5,559,462.46	2,241.19	$227,408.71
Oct	-	-	-	-	$8,136,241.54	156.14	$15,614.40
Nov	-	-	-	-	$8,547,332.79	308.52	$32,073.50
Dec	-	-	-	-	$8,917,337.23	376.86	$40,346.10
Total	**2,980.83**	**$1,425,272.55**	**26.70**	**$10.00**	**$77,627,855.59**	**42,528.19**	**$5,134,406.18**

(a) Payments = MW x LMP.

3.5.3.5 Analysis of Real-Time Price-Response Program Interruptions

Real-time interruptions occurred on practically every nonholiday weekday because of the high frequency with which the Real-Time Price-Response Program is activated. In 2008, the Real-Time Price-Response Program was activated a total of 207 distinct days out of 256 nonholiday weekdays. The ISO calls a real-time price event whenever a forecasted price reaches or exceeds $100/MWh in any program hour for the following operating day. Forecasted prices include Day-Ahead Energy Market prices and the forecasted LMPs calculated during the ongoing Reserve Adequacy Analysis process. System operators use the RAA process internally to manage the system reliably. Because price forecasts, not actual real-time prices, activate the Real-Time Price-Response Program, the program is subject to forecast error. The program can result in interruptions when the real-time price is below $100/MWh or fail to be activated when the real-time price exceeds $100/MWh.

The average real-time LMP at the Hub during eligible program hours for 2008 was $92.92/MWh, while the price-response program guarantees a minimum payment of $100/MWh. At the monthly level, April through July were the only months that had average real-time LMPs over $100/MWh, as shown in Table 3-17. As of December 2008, 86.1 MW were enrolled in the Real-Time Price Response Program (about 3.4% of the total enrolled megawatts); payments for this program totaled $5.1 million, which is about 6.1% of the total payments made to demand-resource programs in 2008. These payments translate to $4.969/kW-month, which is greater than the transition payment of $3.750/kW-month that capacity resources currently receive.

Table 3-17
Average Hub Real-Time LMPs for Real-Time Price-Response Program Hours

Month	Average. Real-Time Hub LMP
Jan	$95.36
Feb	$77.79
Mar	$78.68
Apr	$107.95
May	$126.34
Jun	$134.21
Jul	$142.64
Aug	$82.70
Sep	$73.92
Oct	$63.12
Nov	$68.81
Dec	$63.55

The $100 trigger price for this program suffers from the same issue as the $50 trigger price for the DALRP, which was fixed and did not vary with fuel prices. Given the small enrollment in the program, the decreasing fuel prices in 2009, and the expected expiration of the program, addressing this issue may not be necessary. However, if program enrollment increases or the program is extended, the trigger price problem should be addressed by establishing a fuel-based threshold similar to the minimum price offer created for the DALRP.

3.5.4 Real-Time Demand-Response and Profiled-Response Program Audit Performance, August 2008

On August 20–22, 2008, in accordance with the ISO's load-response program rules, the ISO conducted an audit of the resources participating in the Real-Time Demand-Response and Profiled-Response Programs on these days, with the exception of Action 9 in NEMA.[116] All the real-time reliability program resources were activated on these days for audit purposes. As provided in the program rules, the audit was unannounced and was conducted as a real program event. The activations of the programs during the audit were staggered across three days from 2:00 p.m. to 5:00 p.m.

Figure 3-36 and Figure 3-37 illustrate the measured energy reduction of the resources reporting data to the ISO, relative to the expected energy reduction had the resources achieved their enrolled maximum interruptible capacity.

[116] *Market Rule 1* requires the ISO to conduct a demand-response program audit for any zone that was not part of an OP 4 event before August 15, 2005. The rule requires the audits (when necessary) to occur between August 15 and August 31.

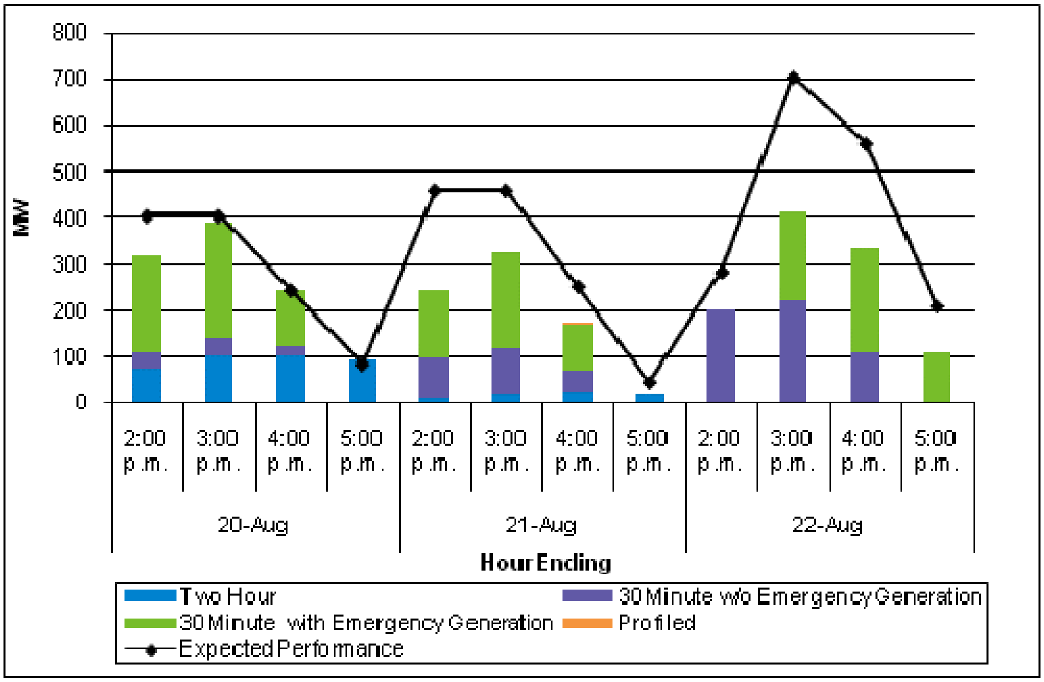

Figure 3-36: Real-time demand-response audit performance, August 20–22, 2008.

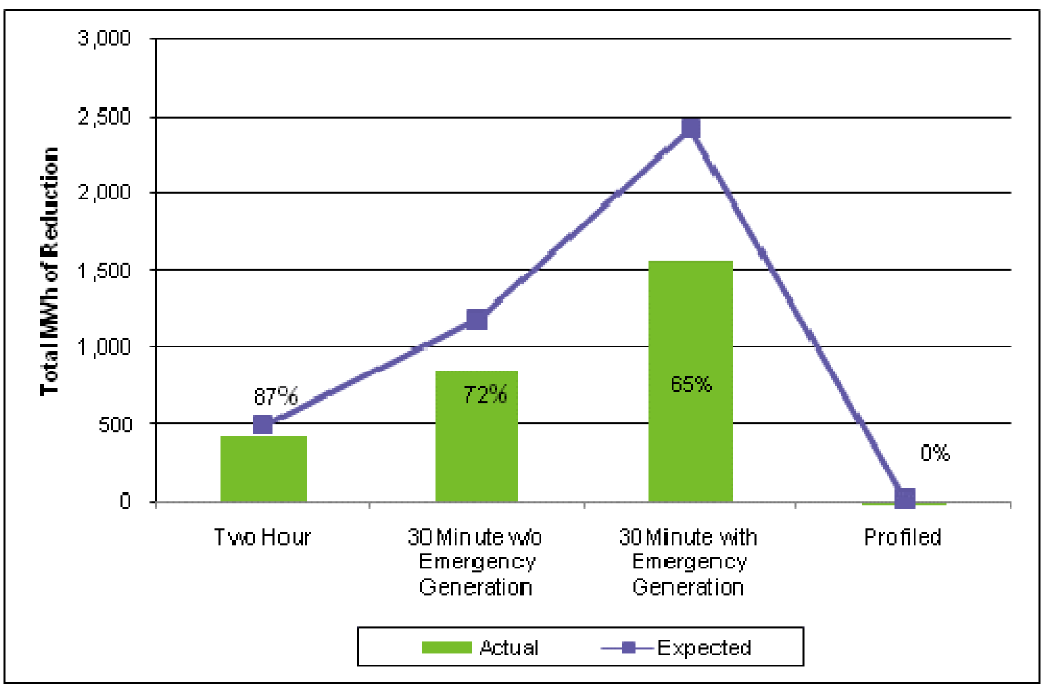

Figure 3-37: Total megawatt-hour reduction by program, 2008 audit.

The total energy reduction from these reliability-program resources over the audit period was 2,918 MWh. The performance of real-time demand-response resources is measured as the ratio of the actual megawatt-hours of load reduced during a load-response or audit event to the expected megawatt-hours of load to be reduced. The expected megawatt-hours of load reduced is the product of the load-curtailment capability (in MW) registered into the Real-Time Demand-Response Program multiplied by the duration (in hours) of the actual load-response or audit events. Using these metrics, the average performance of real-time demand-response resources since 2003 has been about 76%. The observed average performance of real-time demand-response assets of 69% during the August 2008 audit event is somewhat below the average performance across the entire history of the load-response program.

The observed demand-response performance factors are attributed to demand-response providers registering an aggressive amount of load-curtailment capability into the program that may result in enrollments greater than the resources' capability. Demand-response providers in the current program have the incentive to be aggressive in their load-curtailment estimates because they receive monthly capacity payments based on their registered load-curtailment estimates until a load-response or audit event occurs. Months may pass before an actual load-response or audit event occurs. If a demand-response asset underperforms during a load-response or audit event, the capacity rating of the asset is reduced going forward, but this underperformance has no impact on the capacity payments the asset received since the previous event or audit took place. The ISO is investigating methods to limit the impacts of possible overenrollment by making the customer registration process more consistent with the FCM rules.

3.5.5 Conclusions about Demand Resources

Enrollment in demand-resource programs grew 28% from December 2007 to December 2008. The Real-Time 30-Minute Program, Real-Time Two-Hour Program, and ODRs experienced the highest increases in enrollment because these programs all are eligible to receive forward-capacity transition payments. A total of $78 million in transition payments was made to demand resources.

As a result of the FERC filing in February 2008, the frequency of megawatts clearing in the Day-Ahead Load-Response Program has decreased significantly. As a result of not clearing every day, customer baselines are no longer static.

The Real-Time Price-Response Program is activated on almost every nonholiday weekday because of the static trigger price of $100/MWh. This issue was especially relevant in 2008, when average LMPs were higher, not because of higher load levels, but because of higher fuel prices. The ISO is evaluating this program to determine whether it will continue beyond May 31, 2010. If it continues, the $100/MWh trigger price should be changed to an indexed trigger price.

Section 4
Capacity Market

This section provides a brief discussion of the inputs and outcomes of the first two Forward Capacity Auctions. FCA #1, for the commitment period of June 1, 2010, through May 31, 2011, was held February 4–6, 2008. FCA #2, for the commitment period of June 1, 2011, through May 31, 2012, was held December 8–10, 2008. More detailed analysis of the Forward Capacity Market, the FCAs, and the INTMMU recommendations will be published in June 2009. Refer to Section 2.2 of this document for an explanation of the FCM, the auction process, and INTMMU oversight. More 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.[117]

4.1 Installed Capacity Requirements

The Installed Capacity Requirement was 32,305 MW in FCA #1 and 32,528 MW in FCA #2. Neither auction had local sourcing requirements; each potential import-constrained area was determined to have sufficient existing capacity. Maine was modeled as an export-constrained capacity zone in both auctions; FCA #1 had a 3,855 MW maximum capacity limit, and FCA #2 had a 3,395 MW MCL.

4.2 Qualification of Resources

Table 4-1 summarizes the qualified existing capacity included in each FCA. These values do not include delist bids or any new capacity resources being treated as existing resources in the auction.[118] Table 4-2 shows qualified new capacity that participated in the auctions.

Table 4-1
Qualified Existing Capacity, MW

Capacity Type	FCA #1	FCA #2
Generation	31,447	31,401
Imports	1,269	1,311
Demand resources	1,990	2,978
Total	**34,705**	**35,690**

Table 4-2
Qualified New Capacity Participating in the Forward Capacity Auctions, MW

Type of Resource	FCA #1	FCA #2
Generation	2,353	3,299
Imports	658	2,613
Demand resources	1,449	1,176
Total	**4,459**	**7,088**

[117] The ISO's FCM filings and orders are available at http://www.iso-ne.com/markets/othrmkts_data/fcm/filings/index.html.

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

4.3 Cost of New Entry

For FCA #1, the cost of new entry was set at $7.50/kW-month for the Maine and Rest-of-Pool capacity zones. Accordingly, the FCA starting price was $15.00/kW-month (CONE × 2). The auction consisted of eight rounds and concluded when the price reached the floor price of $4.50/kW-month (CONE × 0.6).

For FCA #2, the CONE was set at $6.00/kW-month using a formula that set the CONE equal to $3.75/kW-month plus 50% of the FCA #1 capacity clearing price.[119] The starting price for FCA #2 was $12.00/kW-month, and the auction concluded after eight rounds when the price reached the floor price of $3.60/kW-month.

4.4 Cleared Capacity and Delistings

Each of the first two FCAs concluded with excess capacity. In FCA #1, 34,077 MW cleared, an excess of 1,772 MW over the ICR of 32,305 MW. In FCA #2, 37,283 MW cleared. This was a surplus of 4,755 MW over the ICR of 32,528. Table 4-3 shows cleared capacity by resource type for both auctions.[120]

Table 4-3
Capacity Cleared in Auctions, MW and Percentage of Total

Type of Resource	FCA #1	FCA #2
Generation	**30,865 (90%)**	**32,207 (86%)**
Existing	30,825	31,050
New	40	1,157
Imports	**934 (3%)**	**2,298 (6%)**
Existing	934	769
New	0	1,529
Demand resources[(a)]	**2,279 (7%)**	**2,778 (8%)**
Existing	1,419	2,330
New	860	448
Total	**34,077**	**37,283**

(a) The 2,778 total for demand resources for FCA #2 reflects the 600 MW RTEG cap. An additional 159 MW of RTEGs above the cap also were procured, making the total demand resources 2,937 MW.

[119] See the ISO tariff, Section 13.2.4, for additional information on how the CONE is derived; http://www.iso-ne.com/regulatory/tariff/sect_3/09-2-16a_mr1_sect_13-14.pdf.

[120] Demand resources include some resources termed *real-time emergency generators* (RTEG). RTEG is distributed generation that the ISO calls on to operate during certain voltage-reduction or more severe actions but must limit its operation to comply with the generation's federal, state, or local air quality permit(s), or combination of permits. Real-time emergency generators are required to begin operating within 30 minutes, which results in increasing supply on the New England grid, and also to continue that operation until receiving a dispatch instruction allowing them to shut down. Because real-time emergency generators are allowed to run only during voltage-reduction or more severe actions, the market rules limit their total obligation to 600 MW.

In FCA #1, existing resources requested to delist 1,300 MW. A total of 970 MW were approved, and 330 MW were rejected. In FCA #2, delist requests totaled 890 MW; all these requests were approved. Qualified new resources can leave the auction without delisting.

When FCA #1 was conducted in February 2008, 3,200 MW of capacity were under Reliability Agreements. The total annualized fixed-revenue requirement for this capacity was $290 million. In FCA #1, the Norwalk Harbor units, which are under a Reliability Agreement, had their delist bid denied. No capacity under a Reliability Agreement sought to delist in FCA #2.

4.5 Net Revenue Analysis

In the long run, the revenues a participant receives from the energy, capacity, regulation, and reserve markets are expected to cover the full costs for the participant to build and operate a proposed new generating plant, including a competitive return on investment. Revenues consistently below this level would discourage entry into the market, eventually putting upward pressure on prices, while revenues above this level most likely would lead to new entry and exert downward pressure on prices. The margin between a plant's market revenues and its variable costs (primarily fuel costs for fossil units) contributes to the recovery of its fixed costs, including nonvariable O&M expenses and capital costs. This margin can be estimated, given the variable costs of a typical new generating unit, hourly energy-clearing prices in New England, and revenue estimates for capacity and ancillary services.

Figure 4-1 and Figure 4-2 present an estimate of the theoretical maximum net revenues for two hypothetical new entrant gas-fired generators—an efficient combined-cycle natural-gas-fired plant with a heat rate of 7,900 Btu/kWh and a gas-fired combustion-turbine unit with a heat rate of 10,900 Btu/kWh. The estimated revenues include upper-bound estimated payments for electric energy, regulation service, reserves, and capacity, which are not representative of actual financial conditions for individual generators in New England. The analysis assumes that each generator runs during all hours when the price is above its marginal cost, ignoring commitment costs, ramping constraints, and start-up and minimum run times. By ignoring start-up costs and generator inflexibility, particularly for combined-cycle units, the calculations can overstate actual net revenues.

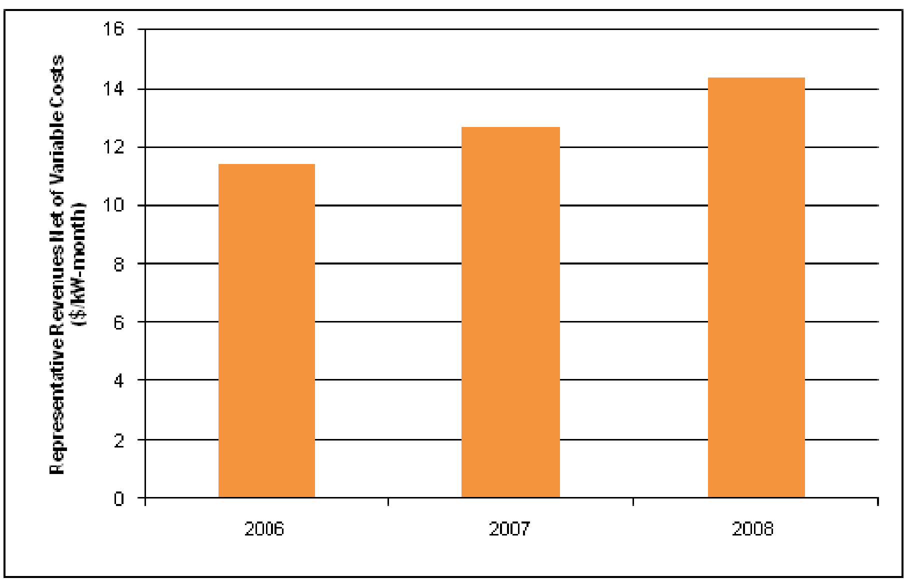

Figure 4-1: Net revenues of a representative combined-cycle generator, 2006 to 2008.

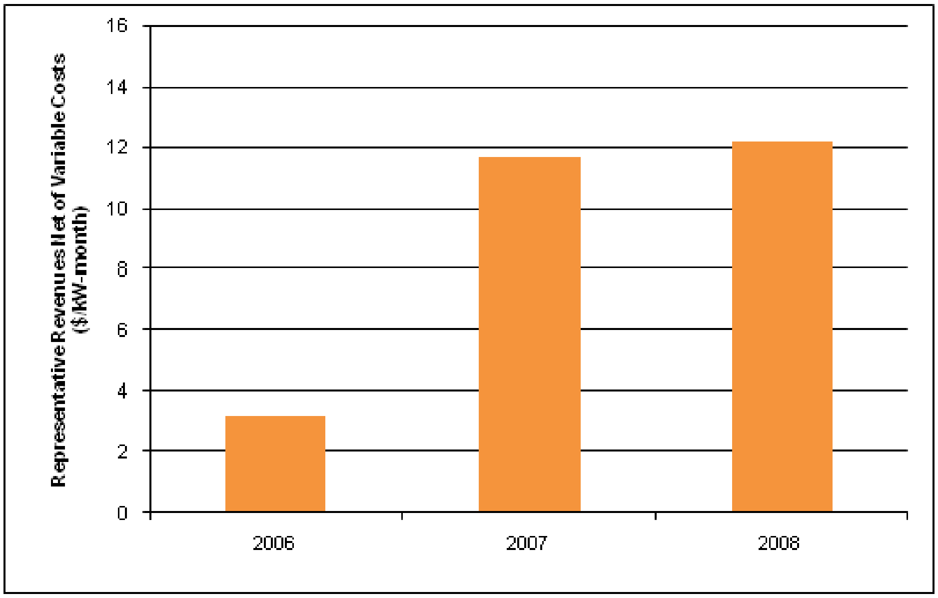

Figure 4-2: Net revenues of a representative combustion-turbine generator, 2006 to 2008.

Under these assumptions, the combined-cycle plant would have earned a theoretical maximum of about $14.43/kW-month in the electric energy, capacity, regulation, and reserve markets during 2008, net of variable costs. The combustion-turbine plant would have earned a theoretical maximum of approximately $12.21/kW-month.

The net revenue of the representative combined-cycle generator in 2008 increased 14% from the 2007 estimate. For the representative combustion turbine, the estimated net revenue increased 5% from 2007 to 2008. Because oil was more expensive than natural gas in 2007 and 2008, when oil is the marginal fuel, resources that burn natural gas (as the ones in the analysis) are likely to earn inframarginal revenues, which would contribute to an increase in estimated net revenues.

The net revenues for the representative combined-cycle and combustion turbine generators by zone are presented in Figure 4-3 and Figure 4-4. Differences in revenues between zones, other than differences in LMPs, can be attributed to zonal differences in reserve market payments.

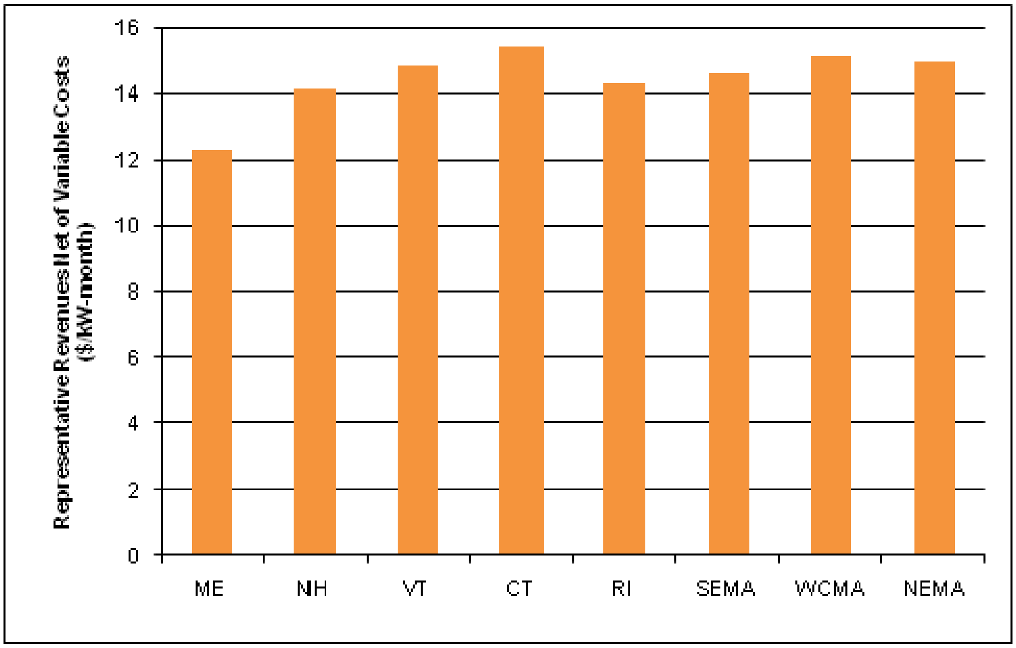

Figure 4-3: Zonal net revenues for a representative combined-cycle generator, 2008.

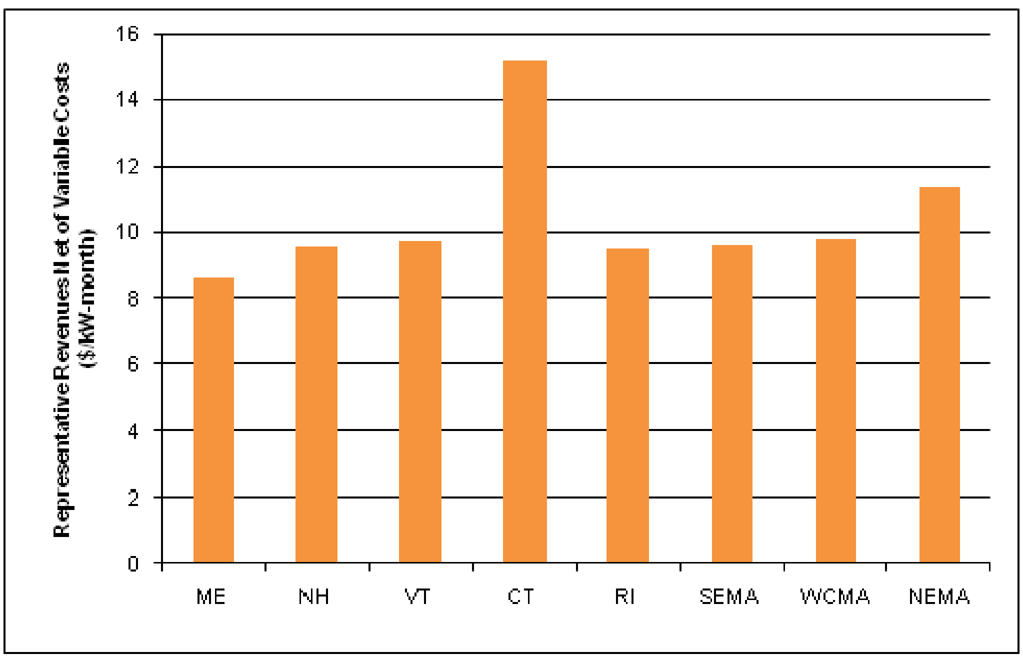

Figure 4-4: Zonal net revenues for a representative combustion-turbine generator, 2008.

Section 5
Reserves

The year 2008 was the second full year of the revised reserve markets, which were placed in service in October 2006. At that time, a locational requirement was added to the Forward Reserve Market (FRM), and locational real-time reserve pricing was established. This section provides an overview of the locational Forward Reserve Market and real-time reserve pricing and a summary of 2008 data for the reserve auctions, markets, and pricing levels. Section 2.3 contains a description of the reserve market and real-time reserve pricing. The data appendix, Section 8.2, contains additional information on the technologies providing reserves, forward-reserve bilateral trading, peak-hour reserve margins, settlement details, and the impact of performance capping on reserve capability.

5.1 Forward Reserve Market

Two forward-reserve auctions were conducted in 2008: in April, for summer 2008, and in August, for the winter 2008/2009 period. Systemwide 10-minute nonspinning reserve (TMNSR) auction clearing prices were lower than the 2007 auction prices, but systemwide 30-minute operating reserve (TMOR) prices were greater.[121] The Southwest Connecticut and Connecticut reserve zones continue to have supply deficiencies, despite the increase in reserve capability from new power plants. This capacity deficiency means that all suppliers in these zones are pivotal and the market is concentrated. The auction clearing price was set at the FERC-approved cap of $14.00/kW-month in both the Southwest Connecticut and Connecticut reserve zones. NEMA/Boston TMOR clearing prices fell because of reduced local requirements resulting from transmission improvements.[122]

5.1.1 Overview of FRM Auction Results

Table 5-1 shows the clearing prices for all the forward-reserve auctions to date. The total amount paid for forward reserve in 2008 was $171.0 million, a slight rise from $163.8 million in 2007 (see Section 8.2 for more details on financial settlements).

Table 5-1
Forward-Reserve Clearing Prices, kW-Month

Reserve Zone	Product Type	Winter 2006/2007	Summer 2007	Winter 2007/2008	Summer 2008	Winter 2008/2009
Systemwide	TMNSR	$4.20	$10.80	$9.05	$8.88	$6.74
Systemwide	TMOR	$4.20	$3.55	$0	$6.50	$4.99
SWCT	TMOR	$14.00	$14.00	$14.00	$14.00	$14.00
CT	TMOR	$14.00	$14.00	$14.00	$14.00	$14.00
NEMA/Boston	TMOR	$14.00	$14.00	$8.50	$14.00	$5.55

[121] In general, capacity equal to between one-fourth and one-half of the total 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.

[122] The market rule defines the offer cap in $/MW-month units. Because reserves are a capacity concept, for consistency, this report uses $/kW-month throughout to represent all capacity measures.

Table 5-2 shows, for each auction, the megawatt surplus of total offers above the requirement—or the megawatt shortfall, if the requirement was greater than the total offers. Systemwide TMNSR and TMOR have been in surplus in each auction since the FRM was implemented. However, except for the NEMA zone in the winter 2007/2008 and the winter 2008/2009 auctions, every local reserve product has been deficient and has cleared at the price cap of $14.00/kW-month.

Table 5-2
Auction Surplus or Shortfall by FRM Product, MW

Reserve Zone	Product Type	Winter 2006/2007	Summer 2007	Winter 2007/2008	Summer 2008	Winter 2008/2009
Systemwide	TMNSR	398.5	309.8	387.3	538.1	674.0
Systemwide	TMOR	861.4	703.4	1,093.0	631.9	815.8
SWCT	TMOR	−156.0	−5.0	−286.5	−218.7	−287.0
CT	TMOR	−681.0	−330.0	−416.5	−281.2	−273.9
NEMA/Boston	TMOR	−593.0	−662.2	160.5	−18.0	231.7

5.1.1.1 New England Systemwide Auction Results

The requirements for systemwide TMNSR and TMOR are set based on the largest forecasted first and second contingencies, respectively, and have been stable over time, as shown in Table 5-3 and Table 5-4. The most significant changes over time have been in total supply offered, for which TMNSR has increased each year for both winter and summer auctions. Prices have fallen in general as a result, with the exception of the first auction, which cleared at the lowest price of any auction to date. Offered supply for TMOR, however, has declined from the first summer auction to the second and has fluctuated from year to year in the winter auctions.

Table 5-3
Summary of System TMNSR Auction Results, by Season

Season	Clearing Price ($/kW-month)	Req. MW	Cleared MW	Offered MW	Claim-10 Available MW[(a)]	RSI Capability[(b)]	HHI Capability[(c)]
Summer 2007	$10.80	700	700	1,010	3,550	370	1,362
Summer 2008	$8.88	800	800	1,338	2,741	200	2,362
Winter 2006/2007	$4.20	700	716	1,098	4,595	494	1,428
Winter 2007/2008	$9.05	850	850	1,237	2,735	188	2,374
Winter 2008/2009	$6.74	800	800	1,474	2,870	216	2,177

(a) A resource's ability to provide 10-minute reserve from an off-line state is referred to as "claim-10" capability.

(b) The Residual Supply Index measures the percentage of reserve demand that can be met without the largest supplier. When the demand cannot be met without a supplier, the supplier is termed "pivotal" and can affect market prices

(c) The Herfindahl-Hirschman Index is a measure of market concentration based on generating capacity.

Table 5-4
Summary of System TMOR Auction Results, by Season

Season	Clearing Price ($/kW-Month	Req. MW	Cleared MW	Offered MW	Claim-30 Available MW[(a)]	RSI Capability[(b)]	HHI Capability[(c)]
Summer 2007	$3.55	700	1,211	1,403	3,966	244	1,235
Summer 2008	$6.50	650	1,154	1,282	3,334	204	1,296
Winter 2006/2007	$4.20	700	1,058	1,561	5,215	320	1,356
Winter 2007/2008	$0	700	1,185	1,793	3,249	189	1,297
Winter 2008/2009	$4.99	750	1,159	1,566	3,450	198	1,232

(a) A resource's ability to provide 30-minute reserve from an off-line state is referred to as "claim-30" capability.

(b) The Residual Supply Index measures the percentage of reserve demand that can be met without the largest supplier. When the demand cannot be met without a supplier, the supplier is termed "pivotal" and can affect market prices

(c) The Herfindahl-Hirschman Index is a measure of market concentration based on generating capacity.

In each season, only a portion of total available forward-reserve capability has been offered as supply into the auctions.[123] For systemwide TMNSR, this ratio of offered-to-available capability has increased because of increases in supply from participants and reductions in total available capability (see Section 5.1.2).

Like assessing market concentration in the electric energy markets, market power in the forward-reserve auctions is measured by the Residual Supply Index and the Herfindahl-Hirschman Index (see Section 3.1). The RSI and HHI shown in Table 5-3 and Table 5-4 were calculated based on the total calculated fast-start reserve capabilities available to compete in the Forward Reserve Market (see Section 2.3). The results of both the RSI and HHI analyses are consistent with a competitive market.

Figure 5-1 and Figure 5-2 illustrate the supply curves for the Rest-of-System for the summer and winter auctions, respectively. These curves have not been adjusted downward for the subtraction of capacity transition payments. Actual forward-reserve payment rates are adjusted by subtracting the capacity payment rate from the auction clearing price. The capacity payment rate was $3.05/kW-month through May 2008, at which time it increased to $3.75/kW-month for the remainder of 2008.

[123] TMNSR and TMOR offered into a local reserve auction counts toward the systemwide megawatt requirements in Table 5-3 and Table 5-4.

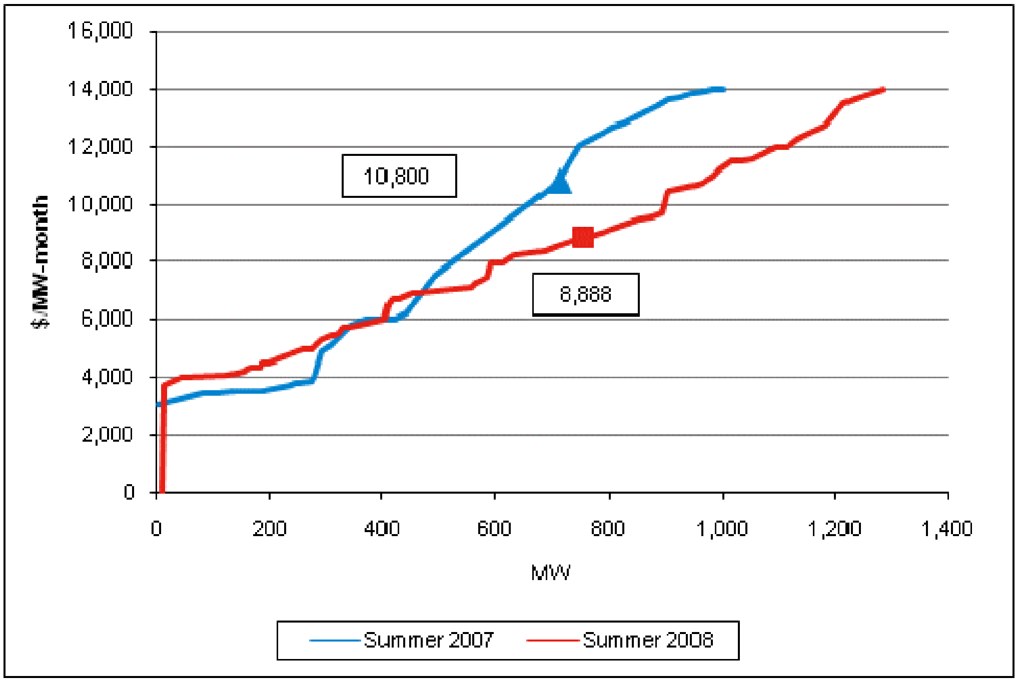

Figure 5-1: TMNSR offer curves for the Rest-of-System zone, summer 2007 and 2008 forward-reserve auctions.

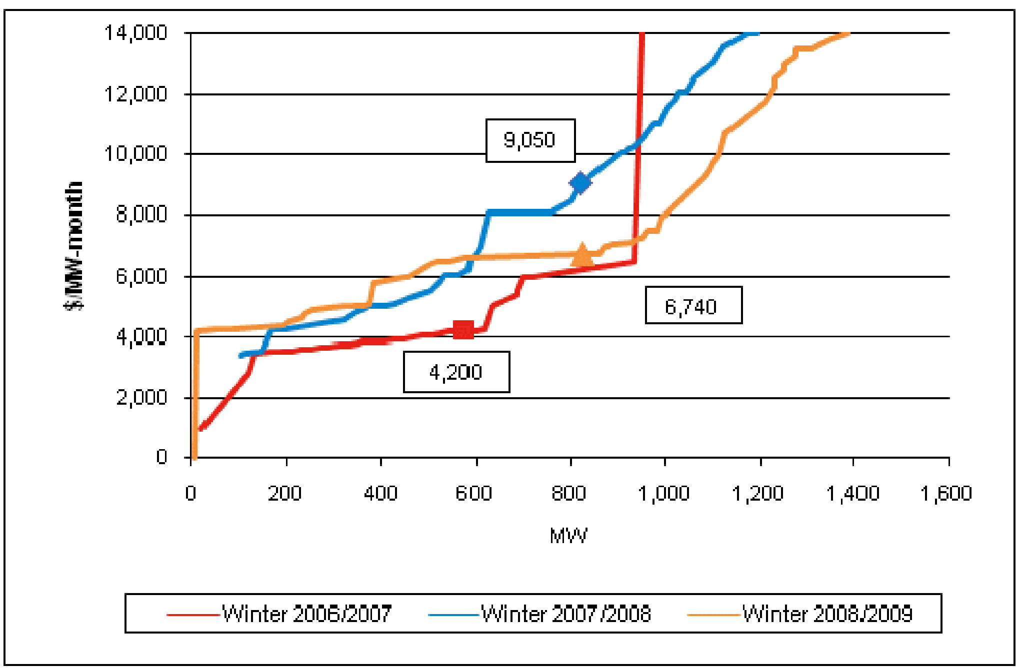

Figure 5-2: TMNSR offer curves for the Rest-of-System zone, winter 2006/2007, 2007/2008, and 2008/2009 forward-reserve auctions.

5.1.1.2 Connecticut and Southwest Connecticut Auction Results

The Connecticut and Southwest Connecticut local reserve zones have cleared at the price cap of $14.00/kW-month in every auction to date. This is because both zones have insufficient supply. In real time, system operators frequently commit additional resources for local reliability protection. Absent these supplemental commitments for spinning reserve, both CT and SWCT would be capacity deficient.

Table 5-5 shows the auction results for TMOR in Connecticut. Although the reserve zone is still short of meeting its requirements, the quantity of megawatts offered increased from 725 MW to 874 MW from summer 2007 to summer 2008 because of new fast-start capacity that came on line. Because CT claim-30 capability is lower than the full local TMOR requirement, every supplier is pivotal, and an RSI calculation is uninformative.

Table 5-5
Summary of Connecticut TMOR Auction Results, by Season

Season	Clearing Price ($/kW-Month)	Req. MW	MWs Cleared	MWs Offered	Claim-30 Available (MW)	RSI Capability	HHI Capability
Summer 2007	$14.00	1,055	725	725	1,006	62	2,358
Summer 2008	$14.00	1,155	874	874	1,124	65	2,137
Winter 2006/2007	$14.00	1,340	659	659	1,112	57	2,358
Winter 2007/2008	$14.00	1,366	950	950	1,076	54	2,090
Winter 2008/2009	$14.00	1,300	1,026	1,026	1,114	57	2,146

Table 5-6 shows SWCT auction results. The megawatt quantities offered are far below total claim-30 capabilities. This is because much of the reserve capability in Southwest Connecticut is being offered into the Connecticut reserve zone during the auction. If cleared, such obligations will receive the same price of $14.00/kW-month but will face less restrictive requirements because they will be called on for statewide shortages only, rather than both statewide and Southwest Connecticut shortages. They will receive the same price, however, because the Connecticut zone is short of the amount needed to meet its reserve requirement, and prices cascade from larger reserve zones to more-restricted reserve zones that are subareas of a surrounding reserve zone. Absent price separation, market participants with TMOR-capable resources in SWCT have no incentive to acquire the more restrictive SWCT obligation when they would be paid the same price to acquire the CT obligation, which can be met by a larger number of resources, either in their own portfolios or through bilateral transactions.

Table 5-6
Summary of Southwest Connecticut TMOR Auction Results, by Season

Season	Clearing Price ($/kW-Month)	Req. MW	Cleared MW	Offered MW	Claim-30 Available MW	RSI Capability	HHI Capability
Summer 2007	$14.00	520	515	515	702	81	3,060
Summer 2008	$14.00	520	301	301	822	99	2,619
Winter 2006/2007	$14.00	550	394	394	788	92	2,548
Winter 2007/2008	$14.00	611	325	325	776	82	2,569
Winter2008/2009	$14.00	610	323	323	821	84	2,622

With the new capacity that has cleared in the first two FCAs and qualified for FCA #3, both CT and SWCT are expected to attain sufficient installed reserve capability in the next few years. The increased supply should make the market for CT and SWCT TMOR more competitive, and prices can be expected to decrease in both reserve zones. As more reserve-capable resources and transmission infrastructure are built in Connecticut, the reserve requirements for SWCT and CT will decrease. When the market no longer is physically short, prices will start to fall below the $14.00/kW-month cap.

5.1.1.3 NEMA/Boston Auction Results

In 2007 and 2008, many transmission improvements were made in NEMA/Boston, ultimately increasing external reserve support and lowering the requirements for reserves within the area. In both the winter 2007/2008 and winter 2008/2009 auctions, the clearing prices dropped from the cap (observed in the first winter auction) to $8.50/kW-month and $5.55/kW-month, respectively. In the summer 2008 auction, NEMA was only 18 megawatts short of meeting its requirement of 300 MW.

In NEMA/Boston, offered TMOR exceeded total claim-30 capability in three auctions. This occurs because NEMA/Boston is unique in that a large portion of the reserve capability is provided by the last segments of base-load resources, as opposed to fast-start resources. The area has seen a slight drop in the level of available claim-30 capability, as shown in Table 5-7, which is because of the ISO's capping of generators' claimed capability (see the appendix, Section 8.2, for information on performance capping).

Table 5-7
Summary of NEMA/Boston TMOR Auction Results, by Season

Season	Clearing Price ($/kW-Month)	Req. MW	Cleared MW	Offered MW	Claim 30 Available (MW)	RSI Capability	HHI Capability
Summer 2007	$14.00	1,050	388	388	377	—	2,676
Summer 2008	$14.00	300	282	282	358	69	2,512
Winter 2006/2007	$14.00	910	317	317	358	—	3,338
Winter 2007/2008	$8.50	280	280	441	387	85	2,269
Winter 2008/2009	$5.55	135	135	367	339	154	2,336

5.1.2 Rest-of-System TMOR Auction Requirement and the R-Factor

To comply with the FRM Rest-of-System TMOR requirement, which ensures that reserve resources that clear the auctions are not overconcentrated in a local area, the auction clears reserves outside local reserve zones. The requirement of 798 MW is calculated as the product of a 600 MW base requirement, set in the ISO tariff, and a 1.33 R-factor (see Section 2.3.1) to account for potential failures by reserve resources.

The use of the 1.33 R-factor presumes that only 75% of the resources that are expected to start within 30 minutes will start successfully. Actual experience during the last two years has demonstrated much better performance, however. The average performance for reserve units requested for 30-minute start-ups was 97.25% in 2007 and 98.44% in 2008, as shown in Table 5-8 and Table 5-9. These results would represent an R-factor of less than 1.03.

Table 5-8
Claim-10 Audit Results for Fast-Start Reserve-Capable Generating Units, 2007 and 2008

Quarter	% Success (Hydro)	% Success (Thermal)	% Success (All)
2007			
First	94.86	57.26	76.80
Second	93.89	69.15	78.53
Third	96.60	63.45	76.57
Fourth	96.14	80.63	88.78
Total 2007	**95.66%**	**67.86%**	**80.45%**
2008			
First	96.72	77.51	91.42
Second	95.68	78.54	87.55
Third	97.38	85.11	94.49
Fourth	98.12	69.12	94.83
Total 2008	**96.99%**	**78.94%**	**91.60%**

Table 5-9
Claim-30 Audit Results for Fast-Start Reserve-Capable Generating Units, 2007 and 2008

Quarter	% Success (Hydro)	% Success (Thermal)	% Success (All)
2007			
First	99.26	94.18	95.29
Second	99.44	96.74	97.16
Third	99.14	97.41	97.82
Fourth	99.59	97.84	98.42
Total 2007	**99.38%**	**96.58%**	**97.25%**
2008			
First	99.85	98.25	98.94
Second	99.32	97.34	97.94
Third	99.40	97.39	98.51
Fourth	99.13	97.73	98.60
Total 2008	**99.44%**	**97.64%**	**98.44%**

The performance of claim-10 and claim-30 units has improved from 2007 to 2008 most significantly for thermal (nonhydroelectric) units. This observed performance of off-line reserve-capable resources enhances the ability of system operators to provide contingency protection, both locally and systemwide.

The INTMMU recommends that the ISO reevaluate the R-factor and either reduce its value or eliminate it. The results of daily performance audits in 2007 and 2008 for claim-30 units show that actual performance has been much higher than a 1.33 R-factor would imply.

5.1.3 Forward-Reserve Threshold Price

Table 5-10 shows annual totals of delivered reserve (GWh) and the amount that was dispatched for energy. In 2006 and 2007, units delivering reserve were dispatched for energy at a level close to the intended target of 2 to 3% of the time. However, in 2008, the percentage of reserve capability designated for a forward-reserve obligation that was subsequently dispatched for energy grew to 5.1%.

Table 5-10
Delivered Reserve and Dispatched Reserve, GWh, 2006 to 2008

Year	Delivered Reserve	Reserve Dispatched for Energy	Percentage
2006	4,050	124	3.1%
2007	16,303	358	2.2%
2008	18,164	919	5.1%

The INTMMU recommends that the ISO reevaluate whether the forward-reserve threshold price should be calculated more frequently. Because the threshold price is calculated at the beginning of the service month, if fuel prices change significantly within a month, units continuing to offer close to the threshold can be dispatched more frequently than intended by market design and so will have a higher capacity factor. A threshold calculated daily or weekly would be less subject to this type of error.

5.2 Real-Time Reserves and Reserve Settlements

Total real-time reserve credit in 2008 was $16.8 million, an increase from $6.6 million in 2007. Table 5-11 shows real-time reserve credit by product. Real-time credit for 10-minute spinning and 10-minute total grew by more than 300% from 2007 to 2008, while credit for all 30-minute operating-reserve products fell. The large increase was due to overnight shortages of reserves.

Table 5-11
Real-Time Reserve Credit, 2006 to 2008

Year	Systemwide TMSR	Systemwide TMNSR	Systemwide TMOR	SWCT TMOR	CT TMOR	NEMA/ Boston TMOR	Total
2006	$719,286	$1,097,047	$6,205	$498,485	$519,065	$82,178	$2,922,265
2007	$3,053,694	$2,158,986	$140,847	$851,559	$220,593	$143,033	$6,568,714
2008	$9,802,696	$6,428,600	$88,481	$324,018	$77,914	$75,553	$16,797,261

Table 5-12 shows average real-time clearing prices by product. Prices and total credit are closely correlated because physical reserve capability did not change significantly from year to year except in Southwest Connecticut's 30-minute operating reserve, which saw a larger drop in average price than in total credit because of additional TMOR capability that came on line.

Table 5-12
Real-Time Reserve Clearing Prices, 2006 to 2008

Year	Systemwide TMSR	Systemwide TMNSR	Systemwide TMOR	SWCT TMOR	CT TMOR	NEMA/Boston TMOR
2006	$0.27	$0.13	$0.01	$1.05	$1.04	$0.24
2007	$0.41	$0.34	$0.09	$0.43	$0.26	$0.15
2008	$1.67	$1.21	$0.06	$0.12	$0.10	$0.08

Most of the real-time reserve credit in 2008 was incurred in the first half of the year, as shown by Figure 5-3, because of a small number of overnight hours in which the system experienced total 10-minute reserve shortages. When events like this occur, the clearing price of TMNSR is set to the reserve-constraint penalty-factor price of $850, reflecting the high value of TMNSR required to cover the largest first contingency on the system. At these times, the $850 clearing price also cascades to the higher-valued TMSR. As of February 2008, ISO control room operations have been enhanced to anticipate and mitigate circumstances that could result in a repeat of these events. Very high reserve prices have not been observed since then, in either on-peak or off-peak hours.

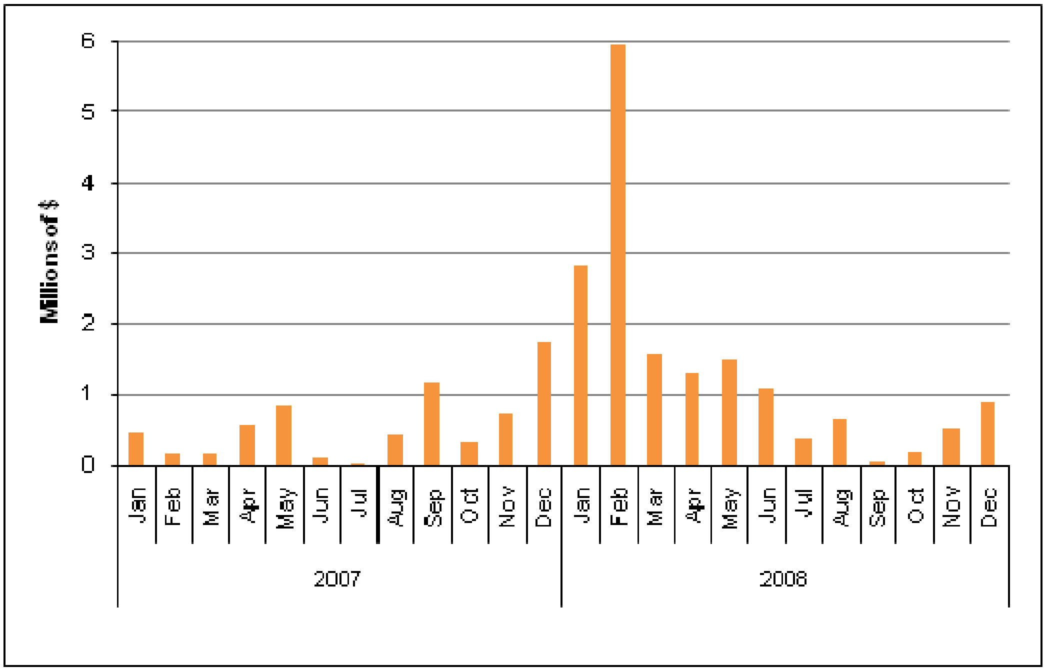

Figure 5-3: Total real-time reserve credit, 2007 to 2008.

Table 5-13 shows total reserve charges for the reporting period that are allocated real-time load obligation. The forward-reserve charges are net of any fail-to-activate or fail-to-reserve penalties, as well as the forward-reserve obligation charge. The forward-reserve obligation charge is the real-time reserve payments made to resources that were designated as forward-reserve resources during the period that had real-time reserve pricing. Additional information on the breakout of forward-reserve credits, penalties, and charges, along with real-time resource credits for 2006 to 2008, is contained in Section 8.2.

Table 5-13
Reserve Charges to Load, by Load Zone, 2008

Market	Product	CT Load Zone	NEMA Load Zone	Rest-of-System
Forward reserves	TMNSR	$14,625,835	$10,717,220	$19,504,890
Forward reserves	TMOR	$65,436,185	$34,456,637	$26,308,611
Real-time reserves	TMNSR	$1,445,816	$1,147,384	$3,301,650
Real-time reserves	TMOR	$232,158	$48,509	$83,980
Real-time reserves	TMSR	$2,401,913	$1,922,632	$5,478,151

Note: The SWCT reserve zone does not have a separate allocation.

Section 6
Regulation

In 2008, the Regulation Market performed effectively. It provided sufficient regulation, was competitive, and helped the New England Balancing Authority Area fully comply with NERC reliability requirements for regulation.

This section presents the 2008 data for the performance of the Regulation Market. Section 2.4 summarizes the function and operation of this market.

6.1 Regulation Requirements and Compliance

For the New England Balancing Authority Area, NERC has set the Control Performance Standard 2 (CPS 2) at 90%. 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%. Figure 6-1 shows the CPS 2 compliance for each month in 2008 and the lower 90% monthly limit required for NERC compliance. The ISO has continually met its more stringent, self-imposed CPS 2 targets.

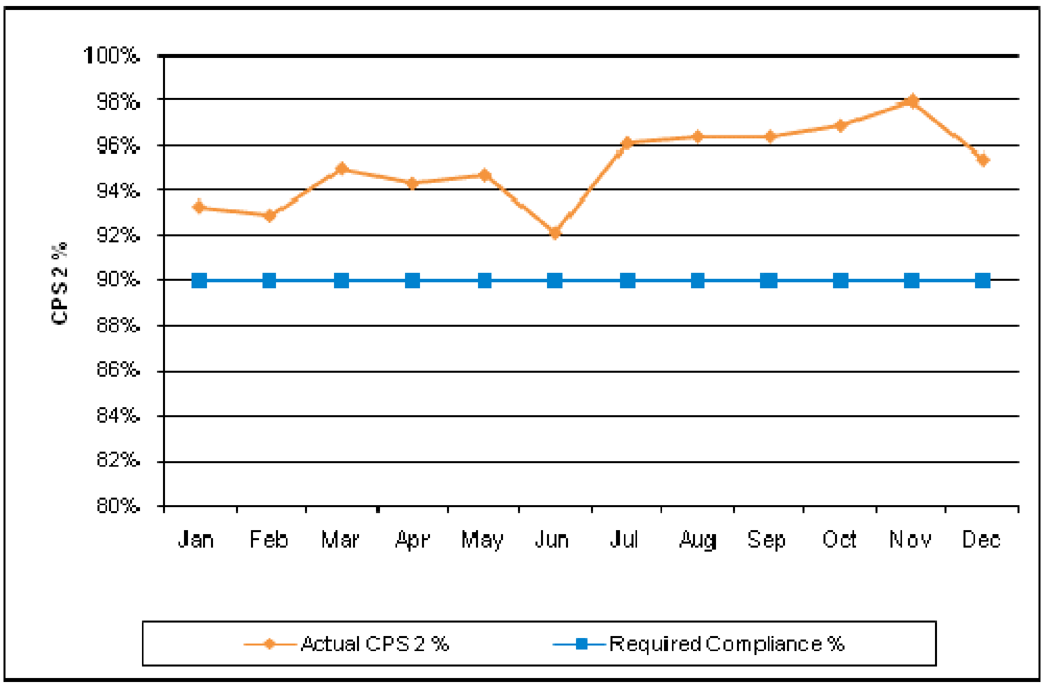

Figure 6-1: CPS 2 compliance, 2008.

In 2008, two improvements were made to the Regulation Market. First, control room operating practices were changed in June to require closer monitoring of load balance and area control error during system energy dispatch. By ensuring that dispatch targets more closely tracked load changes, regulation units were less often pushed to their upper or lower limits, which improved CPS 2. Second, regulation software enhancements made in May and July 2008 improved the handling of regulation units in real time. Together, these changes allowed for both lower regulation requirements and higher CPS 2.

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. They generally are lower during off-peak seasons, spring and fall, than in summer and winter. Figure 6-2 shows the megawatt time-weighted monthly average of the regulation requirements for 2006 to 2008. The ISO has been able to reduce the requirements because unit performance has remained high and because of the software and operational enhancements to the Regulation Market.

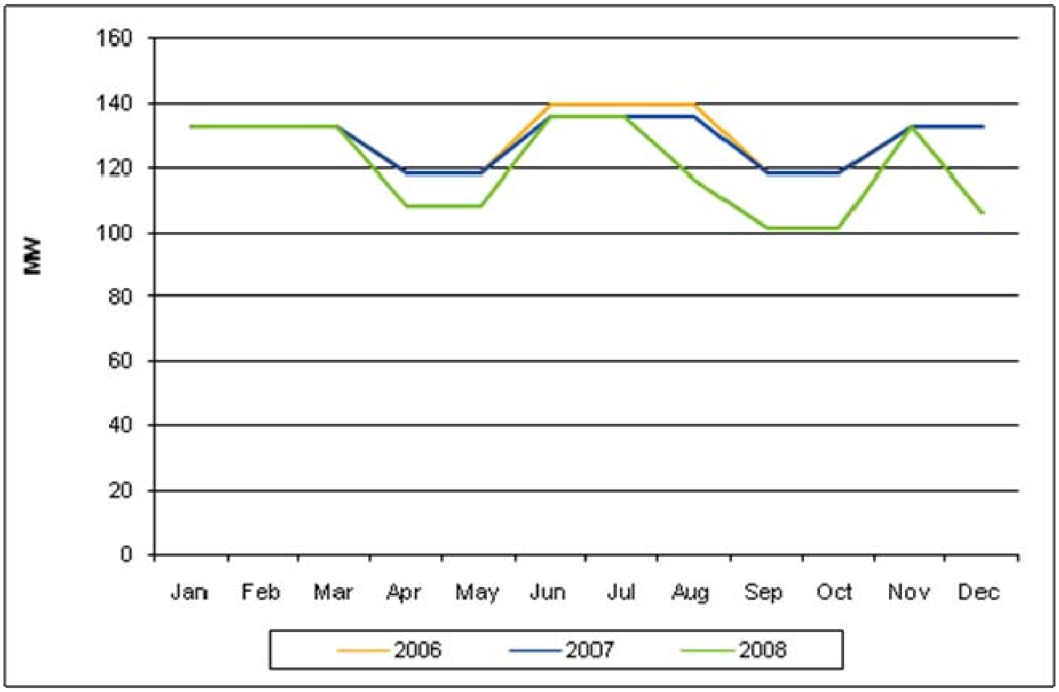

Figure 6-2: Monthly average regulation requirements, 2006 to 2008.

Table 6-1 shows the annual average regulation requirement since 2002. Average regulation values have fallen from 181 MW to 120 MW during the last six years.

Table 6-1
Annual Average Regulation Requirement, 2002 to 2008

Year	Annual Avg. Regulation Req. (MW)
2002	181
2003	171
2004	152
2005	144
2006	130
2007	129
2008	120

6.2 Regulation Capacity

The pool of resources available for regulation hourly is a subset of all active regulation-capable generators and is based on scheduled outages and other real-time conditions. On average, about 6.1%, or 120 MW, of all available regulation capability is required to provide regulation in real-time.

Figure 6-3 shows regulation capability by month for 2008. It shows regulation capability that essentially is in service. Regulation capability is affected at the unit level by ambient temperature and at the system level by outage schedules. Figure 6-3 shows that capability was highest during winter months and lowest during the spring and fall maintenance periods, particularly June and October, when more generators are out for maintenance.

Figure 6-3: Total available regulation capability, 2008.

Figure 6-4 shows regulation capacity and the amount of regulation provided by unit type for 2008. Gas units were the primary provider of regulation, providing approximately 63% of capability and 91% of capacity.

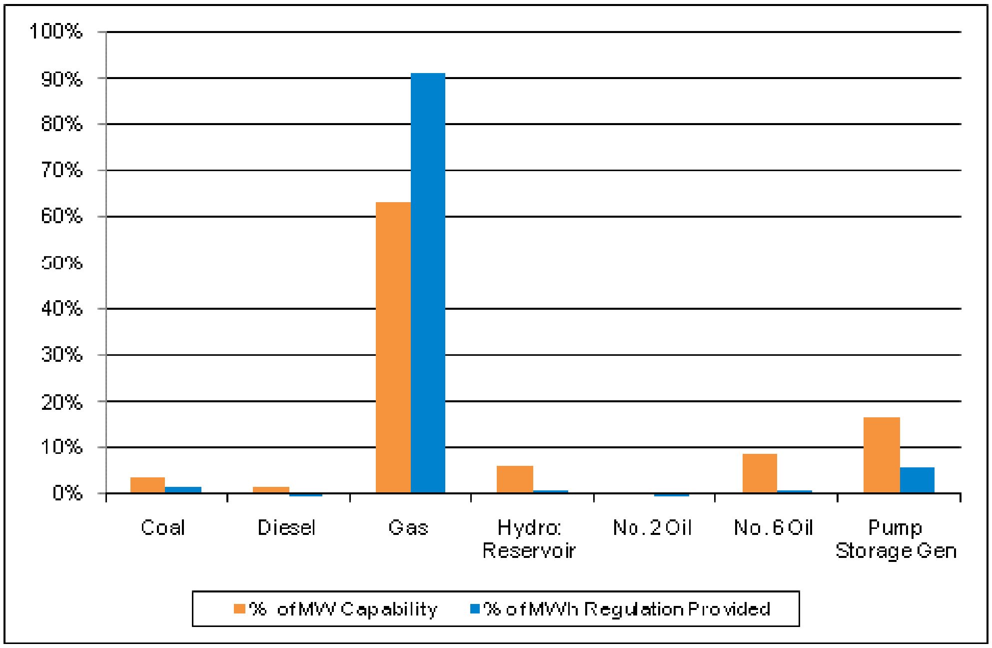

Figure 6-4: Regulation capability and regulation provided by fuel type, 2008.

6.3 Regulation Market Costs and Prices

Figure 6-5 shows total regulation payments by month from January 2007 through December 2008. Payments to generators for providing regulation totaled $50.5 million in 2008, an increase of $6.7 million over the 2007 costs of $43.8 million. The cost increase was caused by two main factors. First, increases in the cost of natural gas increased the opportunity cost of providing regulation. Second, in off-peak hours, natural gas units that were providing lower-cost regulation were decommitted, which required the use of more expensive regulation sources.

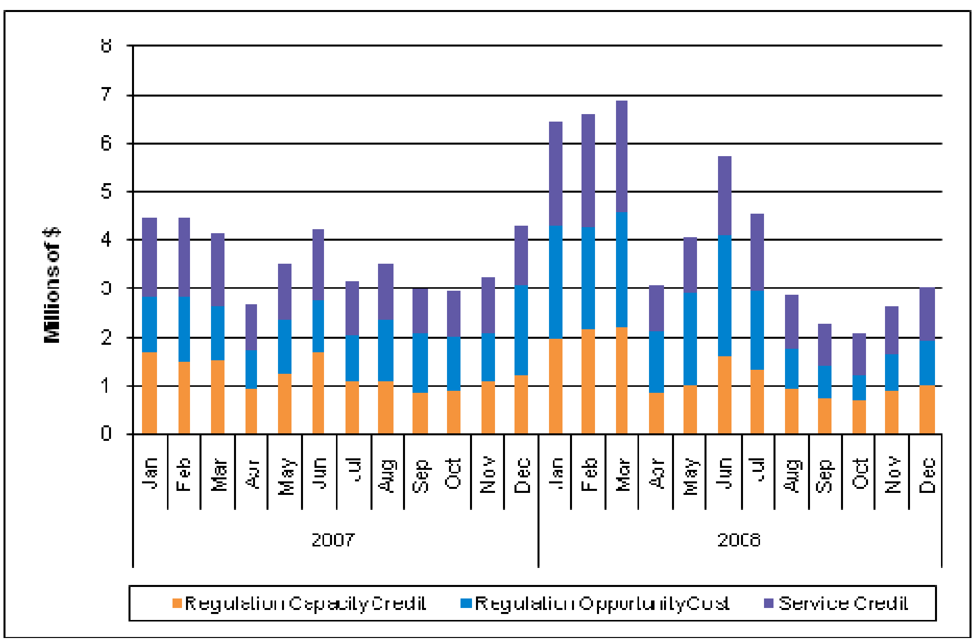

Figure 6-5: Total regulation payments by month, 2007 to 2008.

Table 6-2 summarizes information about clearing prices in the Regulation Market by month for 2008. The annual average regulation clearing price rose 8.7% from $12.65/MWh in 2007 to $13.75/MWh in 2008.

Table 6-2
Monthly Regulation Clearing Price Statistics, 2008

Month	Minimum	Average	Maximum
Jan	$6.98	$19.29	$100.00
Feb	$6.65	$22.96	$100.00
Mar	$6.00	$21.50	$100.00
Apr	$2.38	$10.49	$30.00
May	$2.02	$11.76	$84.49
Jun	$6.38	$15.78	$100.00
Jul	$0.00	$13.04	$85.74
Aug	$6.97	$10.15	$100.00
Sep	$6.97	$9.90	$84.56
Oct	$6.99	$9.33	$22.00
Nov	$6.50	$9.39	$22.53
Dec	$5.99	$11.68	$99.33

As Figure 6-6 illustrates, average 2008 regulation prices were highest during the morning peak hours. The prices declined during the midday and evening peak hours and increased slightly in the late evening. These prices correspond to the availability of regulation units; many are available during the day, whereas supply becomes tighter overnight as units are decommitted.

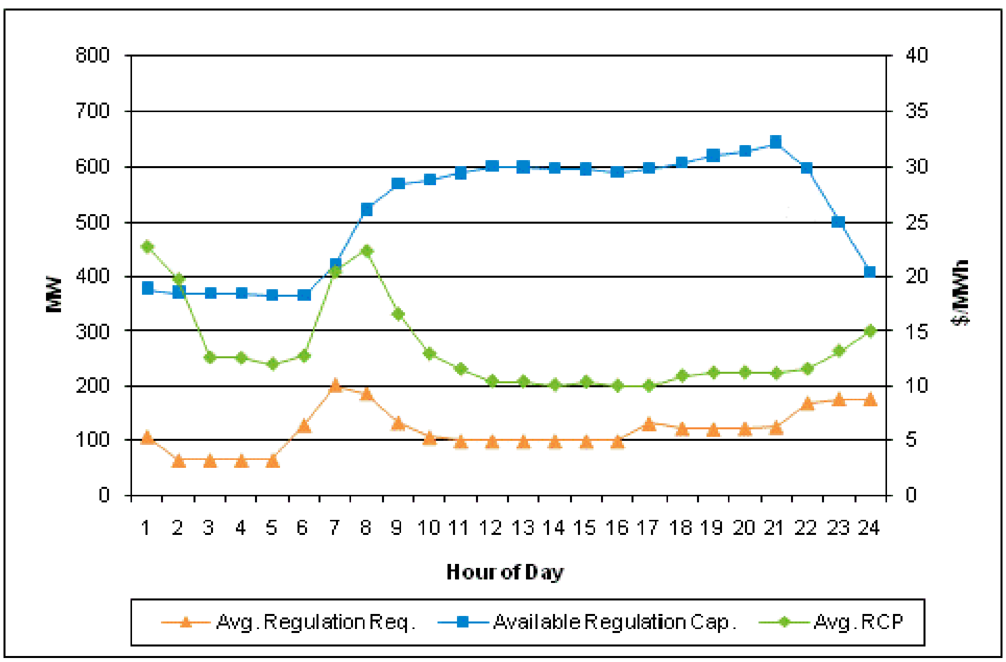

Figure 6-6: Average regulation requirement, available regulation capability, and regulation clearing price, 2008.

6.4 Regulation Market Competitiveness

The competitiveness of the New England Regulation Market is evaluated using two analyses: HHI (a measure of market concentration based on generating capacity), and RSI (a measure of the percentage of reserve demand that can be met without the largest, pivotal supplier, which can affect market price) (see Section 3.1). The HHI for the New England Regulation Market is based on summer capabilities of regulation capacity to offer into the market. The summer period is when the regulation requirements are highest. The values shown were developed from participant information collected by the INTMMU. 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 820 to a high of 932, with an annual average of 871 points. Each of these outcomes is below the U.S. Department of Justice benchmark for an unconcentrated market.[124] The monthly RSIs exceeded 1,000 for every month in 2008. The results of the HHI and RSI analyses indicate that the Regulation Market is structurally competitive.

[124] The DOJ's guidelines for market concentration are available at http://www.usdoj.gov/atr/public/guidelines/horiz_book/15.html).

Section 7
Reliability and Operation

This section discusses the amount of electric energy produced by resources committed in supplement to the market-clearing process and provides details of the costs of these commitments. The section also contains information about the Reliability Agreements in place with generation owners for providing resources deemed necessary for reliability. Total annual data for reliability commitments and generation for 2008 and annual reliability payments and cost allocations for the year are presented and compared with 2007 results. Refer to Section 2.5 for a description of the reliability commitment process and cost allocation.

7.1 Reliability Commitment Results for 2008

Figure 7-1 shows the electric energy output from resources committed for reliability that also received "make-whole" or NCPC payments for day-ahead and real-time commitments made in 2007 and 2008. Most of the reliability commitments were made either as part of the ongoing Reserve Adequacy Analysis process or in real time, both of which are classified as real time for cost allocation purposes. Overall, the total electricity produced by generating units committed for reliability decreased from 3.9 GWh in 2007 to 2.5 GWh in 2008. Electric energy output from reliability commitments made during the Day-Ahead Energy Market decreased 22% between 2007 and 2008. Energy output from reliability commitments made during the Real-Time Energy Market decreased 36%. As a whole, 35% less electric energy was generated by resources committed for reliability in 2008 than in 2007.

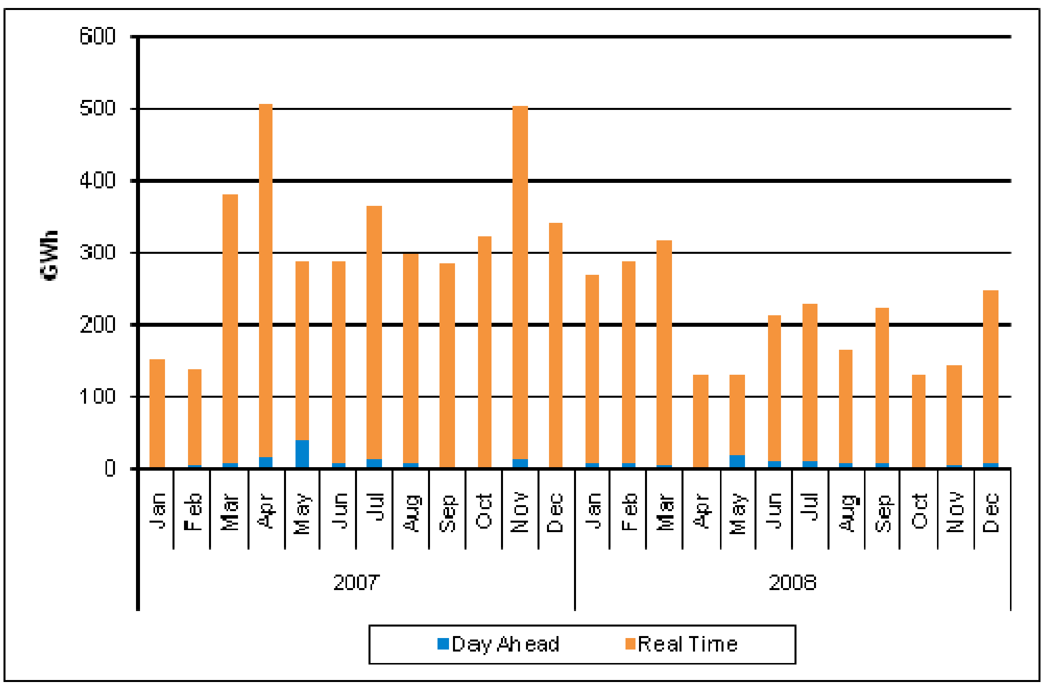

Figure 7-1: Total monthly electricity output from reliability commitments that received NCPC, by commitment period.

Real-time commitments decreased significantly in April 2008, which generally continued through the remainder of the year. The decrease was attributable to revisions in the transmission operating guides for the NEMA zone on the basis of engineering studies that eliminated the need to operate a resource in the NEMA region under many system conditions.

Table 7-1 shows the electric energy that was produced in 2003 to 2008 by resources committed for reliability reasons that also received NCPC for the commitment period. As a percentage of total energy, this reliability energy has varied from 1.6% in 2003 to a maximum of 3.1% in 2005. Since the peak in 2005, reliability energy as a percentage of total energy has been decreasing and dropped below 2% in 2008 for the first time since 2003. From 2007 to 2008, all categories of electric energy committed for reliability decreased; since 2003, most electric energy was committed for second-contingency reliability, 65% of the annual total of 2,549 GWh.

Table 7-1
Generation from Out-of-Merit
Reliability Commitments Paid NCPC, by Type, GWh

Year	Second Contingency	Voltage	Distribution	First Contingency	Total	% of Total Energy
2003	598.59	322.16	44.68	743.94	1,709.37	1.6
2004	454.01	1,183.82	127.50	1,661.85	3,427.18	2.6
2005	1,785.35	977.40	142.39	1,266.51	4,171.64	3.1
2006	2,282.82	327.77	177.36	436.95	3,224.89	2.4
2007	2,704.53	645.06	11.41	528.16	3,889.16	2.9
2008	1,658.05	427.45	4.65	458.75	2,548.91	1.9

Table 7-2 presents the generation from out-of-merit reliability commitments paid by NCPC separated by location. Three areas showed significant reduction in energy from out-of-merit commitments: Southwest Connecticut, Rest of Connecticut, and NEMA. Connecticut and SWCT dropped from 750 GWh in 2007 to 372 GWh in 2008. These reductions in both Connecticut regions were attributable to the completion of construction on two major transmission lines, which eliminated the need to commit resources out of merit.[125] The large drop in out-of-merit energy in the NEMA/Boston area was due to transmission improvements into the Boston area, which eliminated the need to routinely commit resources out of merit for voltage support. Transmission improvements expected in 2009 are anticipated to significantly reduce the need for out-of-merit commitments in SEMA once completed. While the transmission is in the construction phase, the need for out-of-merit commitments may continue, or possibly increase.

[125] The two lines in Connecticut are part of the Middletown–Norwalk projects consisting of 345 kV lines, one from East Devon to Singer, and another from Singer to Norwalk.

Table 7-2
Generation from Out-of-Merit
Reliability Commitments Paid NCPC, by Location, GWh

Year	SWCT	Rest of Connecticut	SEMA	NEMA/ Boston	Rest of System	All of New England
2003	231.25	346.84	97.82	679.04	354.43	1,709.37
2004	210.52	224.27	138.32	2,446.90	407.18	3,427.18
2005	328.85	458.59	368.63	2,683.54	332.03	4,171.64
2006	400.89	574.53	1,240.43	545.72	463.33	3,224.89
2007	327.16	423.09	1,543.29	1,129.19	466.42	3,889.16
2008	270.90	101.58	1,440.68	238.17	497.58	2,548.91

Figure 7-2 presents total monthly reliability payments for 2007 and 2008 by financial settlement category and their combined percentage of total load. Commitments for local second-contingency protection continue to dominate the reliability costs. The decline in voltage payments that began in April 2008 was due to the introduction of new operating guides as also shown in Figure 7-1. The rise beginning in March 2007 is associated with changes in operating-procedure requirements. The overall fall in October 2008, most notably in first-contingency payments, is a result of the decreasing price of No. 6 oil. Reliability resources running No. 6 oil became increasingly less expensive as a result of the drop of their input fuel prices. Table 7-3 shows the total daily reliability payments by category with the percentage change between years. The 50% increase in first-contingency payments from 2007 to 2008 is partly due to the higher average fuel prices in 2008. The decrease in voltage payments by 36% can be attributed to changes in operating-procedure requirements resulting in a significant decrease in voltage payments made to the NEMA zone.

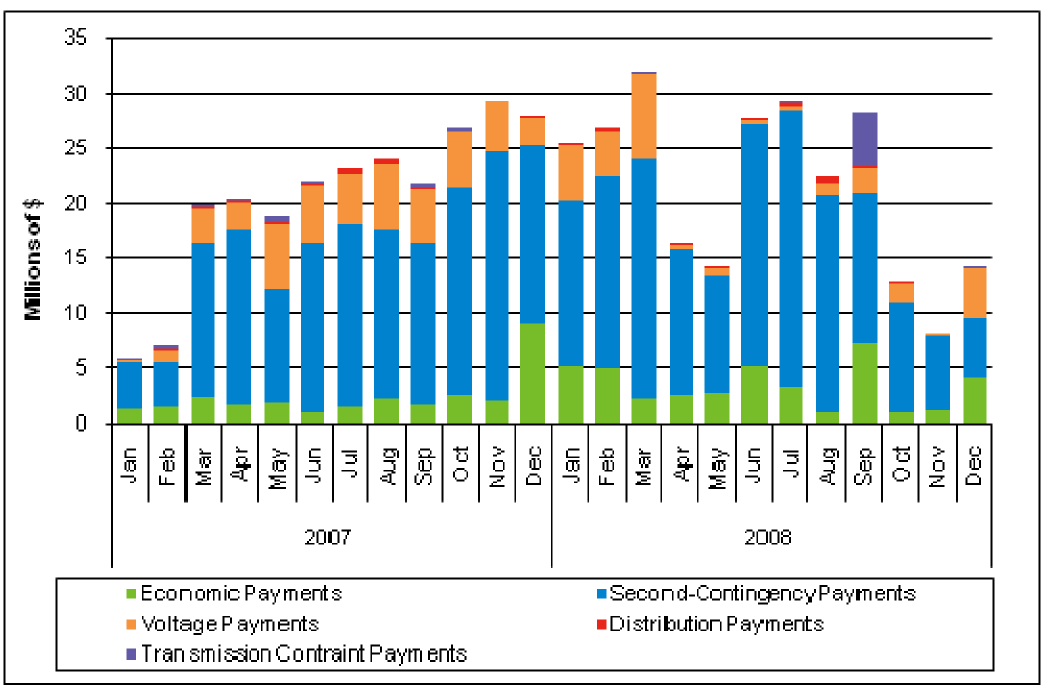

Figure 7-2: Daily reliability payments by month, January 2007 to December 2008.

Table 7-3
Total Daily Reliability Payments, 2007 and 2008, Million $

Payment Type	2007	2008	Difference	% Change
First-contingency reliability payments	29.6	44.4	14.8	50%
Second-contingency reliability payments	169.5	182.5	13.0	8%
Distribution	1.8	1.5	−0.3	−17%
Voltage	46.0	29.4	−16.6	−36%
Total	**246.9**	**257.8**	**10.9**	**4%**

Table 7-4 presents second-contingency reliability payments for day ahead and real time, as well as a combined total of the two, by zone for 2007 and 2008. As a whole, second-contingency payments increased by $13 million from 2007 to 2008. The vast majority of the payments were made to SEMA for both day ahead and real time, which in total accounted for 78.6% of all second-contingency payments in 2008.

Table 7-4
Second-Contingency Reliability Payments by Load Zone, 2007 and 2008, Million $

Load Zone	Day Ahead		Real Time		Total	
	2007	2008	2007	2008	2007	2008
ME	0.0	0.0	2.1	2.7	2.1	2.7
CT	1.3	1.1	34.0	23.2	35.3	24.3
RI	0.0	0.0	0.2	0.1	0.2	0.1
SEMA	2.0	2.5	106.0	141.0	108.0	143.4
WCMA	0.0	0.0	1.7	0.7	1.7	0.7
NEMA	0.9	0.8	21.3	10.5	22.3	11.3
System Total	**4.2**	**4.4**	**165.3**	**178.2**	**169.5**	**182.5**

Table 7-5 shows the average daily real-time second-contingency reliability costs in $/MWh for days with charges, by load zone. The SEMA zone had significantly higher average prices than all other zones, at $9.24/MWh. The next-highest values were NEMA and Maine with $2.98/MWh and $2.20/MWh, respectively.

Table 7-5
Average Daily Real-Time Second-Contingency Reliability Allocations for Days with Charges, 2008, $/MWh[a]

Month	ME	CT	SEMA	WCMA	NEMA
Jan	0.99	1.23	9.97	0.00	4.03
Feb	2.21	0.52	10.15	0.75	4.12
Mar	1.19	3.00	11.31	0.53	4.66
Apr	0.00	1.35	9.37	0.00	1.66
May	0.00	1.37	7.63	0.53	0.00
Jun	5.57	1.37	12.42	0.84	2.96
Jul	0.00	1.88	11.25	0.00	1.87
Aug	0.02	1.24	12.59	0.26	0.00
Sep	2.83	1.17	10.42	0.32	0.00
Oct	0.12	1.18	7.83	0.63	0.00
Nov	0.00	0.75	5.53	0.00	1.79
Dec	4.69	0.35	2.37	0.00	2.74
Annual Average	**2.20**	**1.28**	**9.24**	**0.69**	**2.98**

(a) A $0.35/MWh allocation for the Rhode Island load zone during November is excluded from the table.

Table 7-6 displays the average first-contingency daily reliability costs, expressed in $/MWh, for days with charges. The highest prices for day-ahead and real-time allocations both took place in September 2008, with a price of $1.49/MWh for real-time allocations and $0.66/MWh for day-ahead allocations. Higher prices in September are attributed to transmission work that took place in the lower-west portion of SEMA during that month.

Table 7-6
Average First-Contingency Daily Reliability Allocations for Days with Charges, 2008, $/MWh

Month	Day Ahead	Real Time
Jan	0.06	1.01
Feb	0.04	1.04
Mar	0.06	0.39
Apr	0.07	0.43
May	0.07	0.57
Jun	0.16	0.84
Jul	0.04	0.65
Aug	0.01	0.18
Sep	0.66	1.49
Oct	0.06	0.16
Nov	0.01	0.26
Dec	0.03	1.07
Annual Average	**0.11**	**0.67**

7.2 Reliability Agreements

As of February 12, 2008, Reliability Agreements were in effect for nine generating stations in two load zones, comprising 3,200 MW of capacity.[126] This represents 10.4% of the total systemwide generating capacity. Table 7-7 shows each zone's claimed generating capability for summer and the total capacity of each zone under Reliability Agreements. Connecticut and WCMA are the only zones with Reliability Agreements. Of the two zones, CT has both a greater total capacity under Reliability Agreements, with a total of 2,661 MW under these agreements, and a higher percentage (34.9%) of its summer claimed capability accounted for by these agreements.

Table 7-7
Percentage of Capacity under Reliability Agreements, Effective November 2008

Load Zone	2008 CELT Summer Seasonal Claimed Capability (MW)	2008 Capacity with Cost-of-Service Reliability Agreement	2008 Capacity under Reliability Agreements as % of 2008 SCC
Maine	3,270	0	0%
New Hampshire	4,114	0	0%
Vermont	912	0	0%
Connecticut	7,620	2,661	34.9%
Rhode Island	1,832	0	0%
SEMA	5,997	0	0%
WCMA	3,829	539	14.0%
NEMA	3,317	0	0%
New England Total	30,891	3,200	10.4%

Figure 7-3 shows the total generating capacity with FERC-approved Reliability Agreements on the left-hand axis and total payments made through Reliability Agreements on the right-hand axis. The total annualized fixed-cost requirement for all resources with Reliability Agreements effective December 31, 2008, was $290.2 million, a decrease of over 56% from the 2006 level of $666.9 million.[127] In addition to the Reliability Agreement terminations, FERC settlements with seven of the nine remaining generating stations resulted in lower annualized fixed-cost revenue requirements.

[126] These nine stations include West Springfield 3 and GTs, Berkshire Power, Middletown, Montville, Milford, New Haven Harbor, Bridgeport Harbor, Pittsfield/Altresco, and Norwalk Harbor 1 and 2.

[127] A full year of annualized fixed cost is included in this total for resources with Reliability Agreements effective December 31, 2008, regardless of when the agreement became effective during the year.

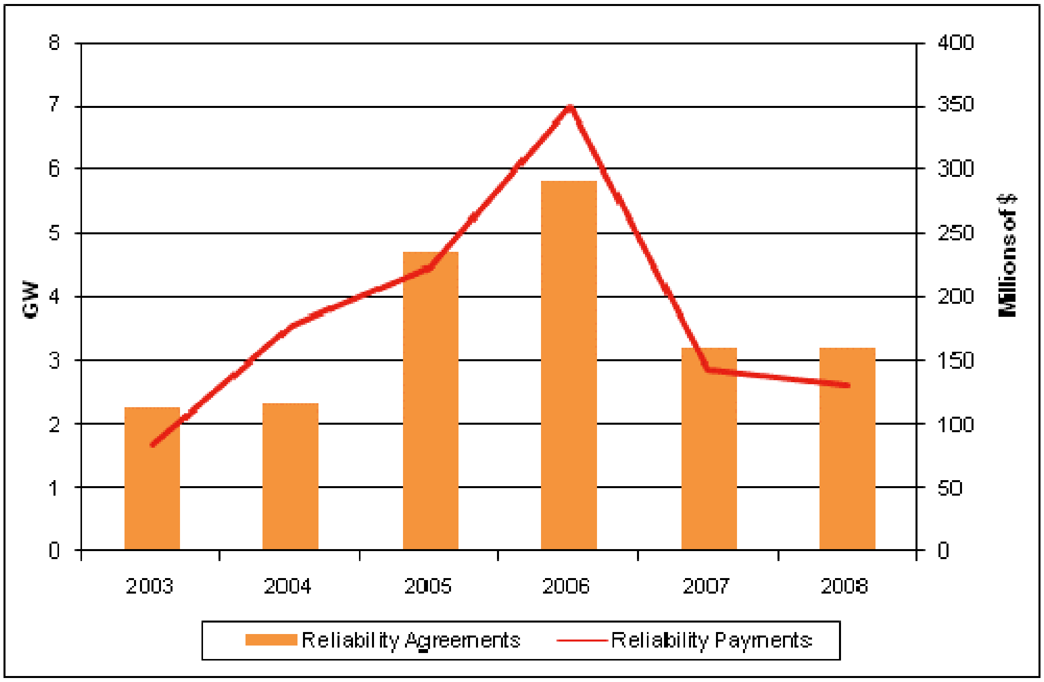

Figure 7-3: Generating capacity with FERC-approved Reliability Agreements.

Table 7-8 shows the annual sum of monthly net payments for 2003 through 2008. The 58.9% drop in net Reliability Agreement payments from 2006 to 2007 is attributable to several factors. The first is the reduction in capacity that operates under cost-of-service Reliability Agreements, and the second is that FERC settlements lowered the approved annualized fixed-cost recovery of a number of the resources with agreements. From 2007 to 2008, net Reliability Agreements decreased by $12.7 million.

Table 7-8
Net Reliability Agreement Payments, System Total, Million $[a]

	2003	2004	2005	2006	2007	2008
Payment	83.4	177.6	223.7	348.7	143.2	130.5

(a) The table shows restated values for previous years that account for the refunds to load associated with the FERC settlements.

7.3 Internal ISO Market Operations Assessment

Various internal initiatives by the ISO took place in 2008 to ensure transparency of the wholesale markets. These initiatives include reviews, audits, and administrative price corrections. This section highlights the 2008 initiatives.

7.3.1 Audits

The ISO participated in several audits during 2008. 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:

- **Review of the Forward Capacity Market Project**—The ISO internal audit department is continuing to review the Forward Capacity Market project including Phase 1 (Capacity Auction) and Phase 2 (Reconfiguration Auction). This review examines 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 to review and certify that the market system software complies with *Market Rule 1*, the manuals, and standard operating procedures. The combination of recertification and testing takes place every two years or sooner, in the case of a major market system enhancement or new market features.

  In 2008, the following market system software certifications were successfully completed:

- Forward Capacity Market Auction software, January 15, 2008, and October 3, 2008
- Forward Capacity Market Descending-Clock Auction software, January 29, 2008
- Locational Forward-Reserve software, December 17, 2008
- Simultaneous Feasibility Test software, December 23, 2008
- Regulation Clearing Price software, December 23, 2008

All certificates are available to participants on request through the ISO external Web site.[128]

7.3.2 Administrative Price Corrections

The ISO continually monitors the processes for calculating locational marginal prices. The ISO takes actions to ensure that the resulting day-ahead and real-time LMPs are accurate. Price corrections are made in the event of a data error, a software program limitation or error, or a hardware or software outage. Generally, these corrections affect LMPs at only a few individual price nodes or for a limited number of five-minute intervals and do not significantly change the hourly LMPs at the Hub or load zones. In total, the number of hours with price corrections decreased over 40%, from 144 hours during 2007 to 83 hours in 2008.

Most of the decrease came from improvements in the dead-bus logic that prevented the need for price corrections at inactive (*dead)* buses, dropping from 84 hours in 2007 to 41 hours in 2008. A *dead bus* results when a point of interconnection to the system where power is available for transmission (i.e., a bus) becomes islanded for a period of time, typically because of a transmission system outage or routine switching and tagging. These buses are not associated with any load, and therefore the prices at those nodes do not have an impact on zonal prices or the Hub price. The ISO's pricing software includes dead-bus logic to assign a price from the nearest active bus to the dead bus. However, at times, because of the limitations of the automated dead-bus logic, the software is unable to find a suitable active node to map to the dead bus. This results in an incorrect price of $0. When this occurs, the ISO manually maps and assigns the correct price to the dead-bus price node. The ISO is working to improve the dead-bus logic and reduce the need to make this type of price correction.

The remaining price corrections were due to hardware and software limitations. The source of all price corrections is shown in Table 7-9.

[128] See http://www.iso-ne.com/aboutiso/audit_rpts/index.

Table 7-9
Administrative Price Corrections

Location/Load Zone	Congestion Component
Data error	7
Hardware/software scheduled outage	3
Hardware/software outage unscheduled	21
Software limitation	10
Software error	1
Dead bus logic	41

Section 8
Data Appendix

8.1 Energy Appendix

Table 8-1 to Table 8-3 show additional details of the marginal congestion and marginal loss components of annual average zonal LMPs, along with annual average differences in day-ahead prices compared with real-time prices, by zone and the Hub. Figure 8-1 compares differences between ISO New England prices and the prices from other eastern ISOs for both day ahead and real time.

Table 8-1
Average Day-Ahead Congestion Component,
Loss Component, and Combined, 2008

Location/ Load Zone	Congestion Component	Marginal Loss Component	Congestion Component Plus Marginal Loss Component
Hub	−$1.12	$0.17	−$0.95
Maine	−$1.71	−$3.69	−$5.40
New Hampshire	−$1.31	−$0.96	−$2.27
Vermont	−$0.94	$0.46	−$0.48
Connecticut	$1.59	$1.79	$3.38
Rhode Island	−$1.40	−$0.73	−$2.12
SEMA	$1.50	−$0.42	$1.08
WCMA	−$0.90	$0.59	−$0.31
NEMA	−$1.29	−$0.33	−$1.62

Table 8-2
Average Real-Time Congestion Component,
Loss Component, and Combined, 2008

Location/ Load Zone	Congestion Component	Marginal Loss Component	Congestion Component Plus Marginal Loss Component
Hub	−$0.39	$0.19	−$0.20
Maine	−$1.53	−$3.86	−$5.40
New Hampshire	−$0.53	−$0.92	−$1.44
Vermont	−$0.33	$0.51	$0.18
Connecticut	$0.63	$1.95	$2.58
Rhode Island	−$0.52	−$0.78	−$1.30
SEMA	$0.98	−$0.38	$0.59
WCMA	−$0.17	$0.63	$0.46
NEMA	−$0.14	−$0.31	−$0.45

Table 8-3
Average Day-Ahead Premium, 2006 to 2008

	2006	2007	2008
CT	$2.75	−$0.06	$1.42
SEMA	$1.31	$1.76	$1.11
ME	$1.05	$0.69	$0.62
VT	$1.11	$1.24	−$0.04
WCMA	$1.22	$1.06	−$0.15
RI	$1.04	$1.11	−$0.20
NH	$0.83	$0.84	−$0.21
NEMA	$0.16	$1.04	−$0.55
Hub	$1.25	$1.25	−$0.13

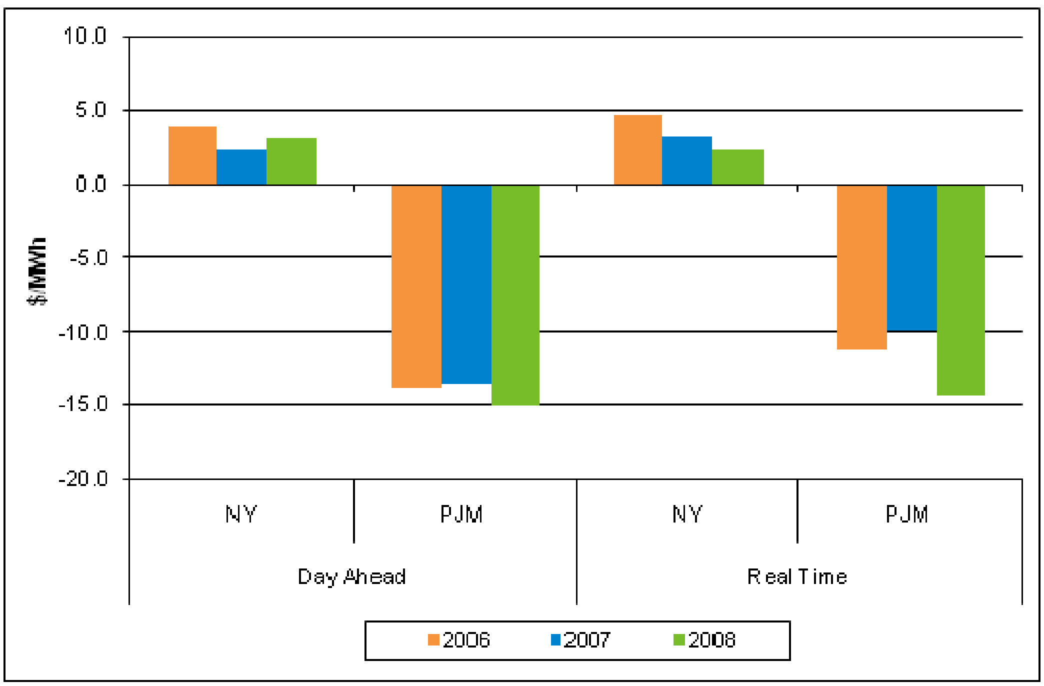

Figure 8-1: Differences between the average New York and PJM day-ahead and real-time prices and the New England prices, 2006 to 2008.

Figure 8-2 to Figure 8-6 present average metered flow by hour over the priced external interfaces with neighboring balancing authority areas.

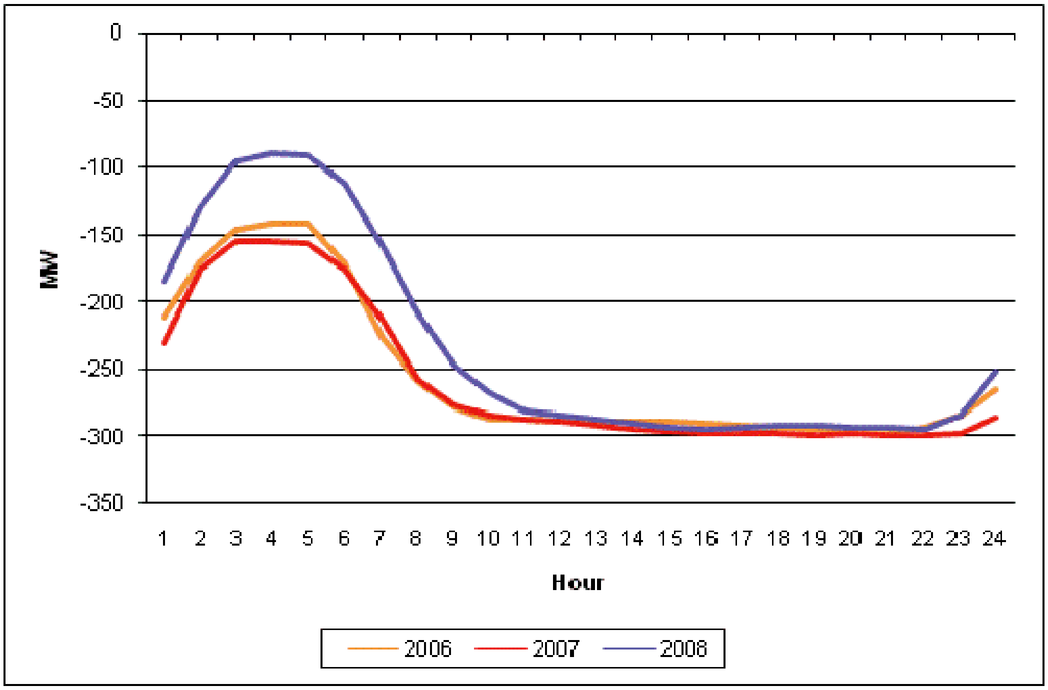

Figure 8-2: New York Cross-Sound Cable, average net metered flow by hour of the day, 2006 to 2008.

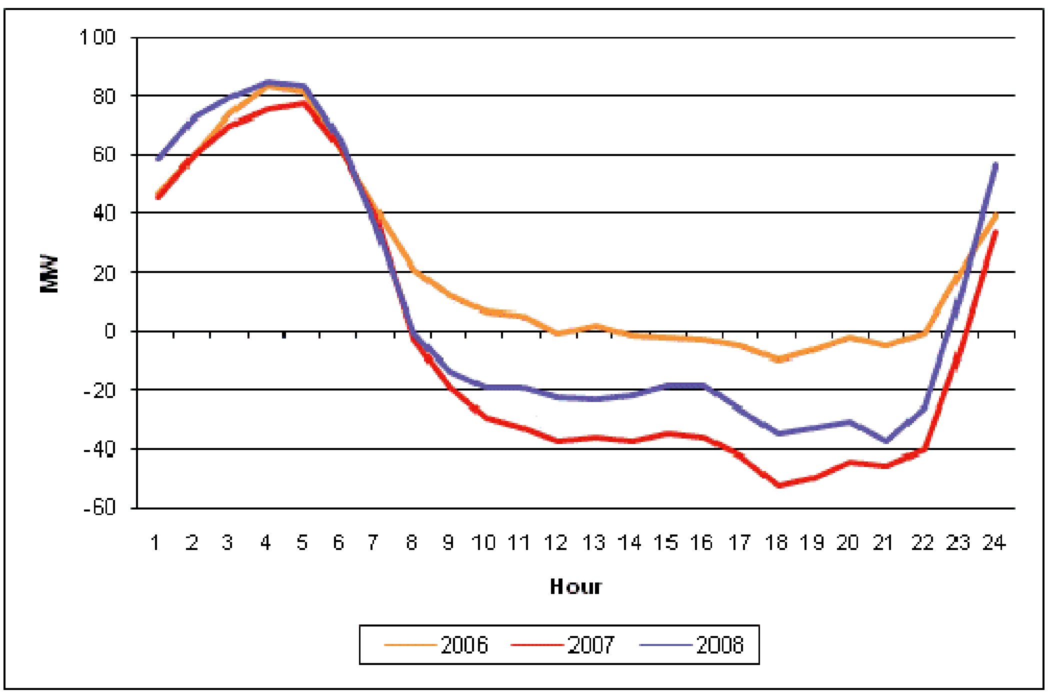

Figure 8-3: New York AC ties, average net metered flow by hour of the day, 2006 to 2008.

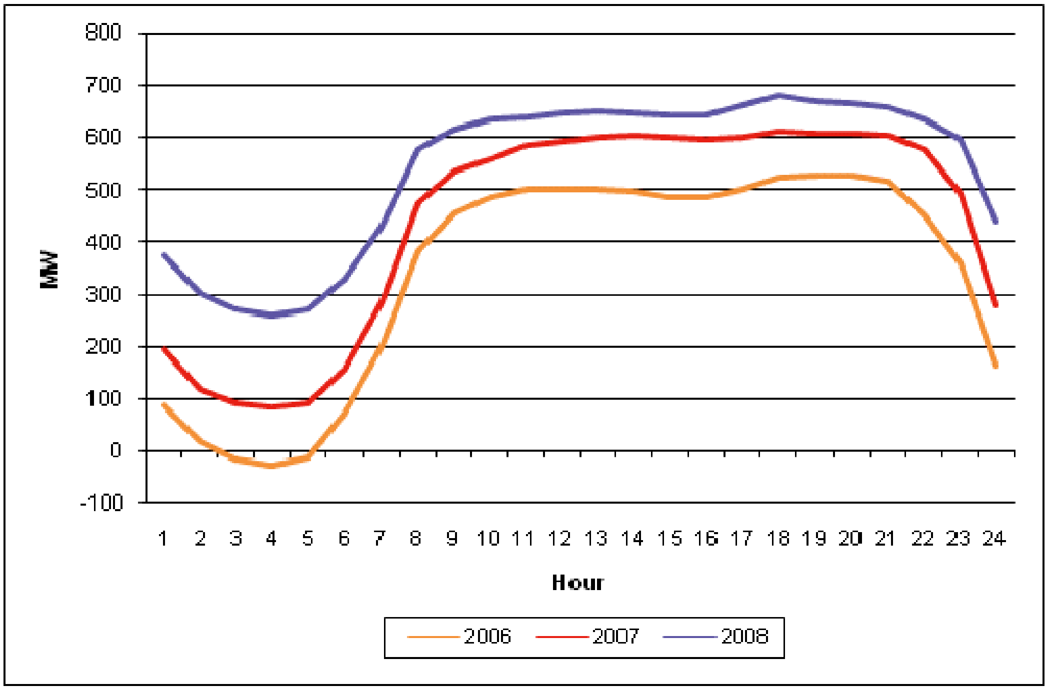

Figure 8-4: Hydro Québec (Phases 1 and 2), average net metered flow by hour of the day, 2006 to 2008.

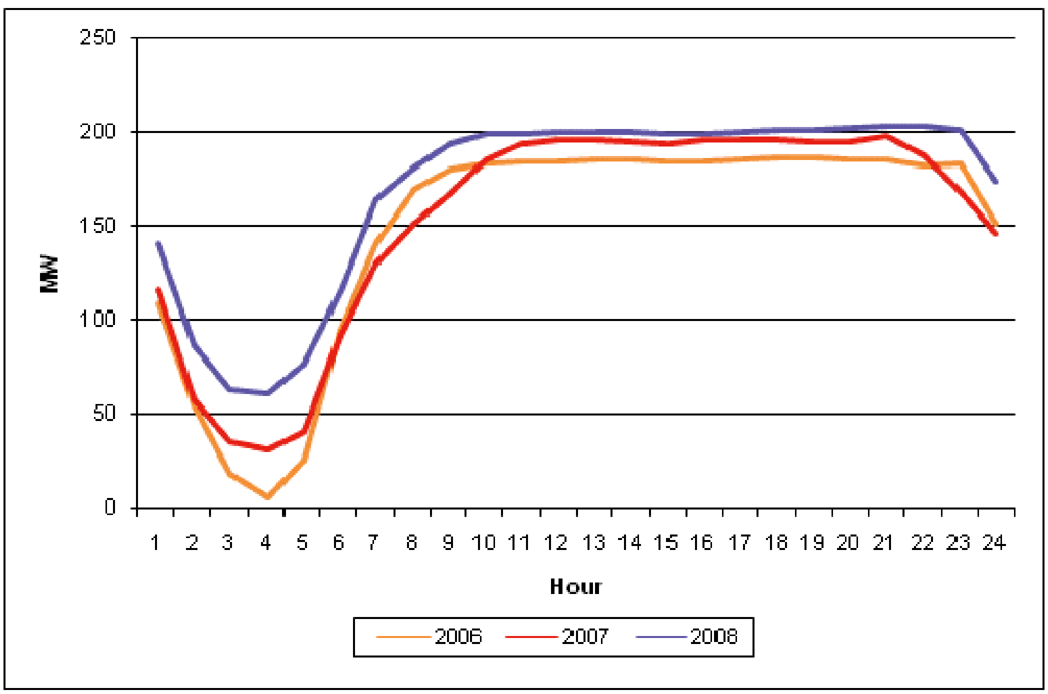

Figure 8-5: Hydro Québec (Highgate), average net metered flow by hour of the day, 2006 to 2008.

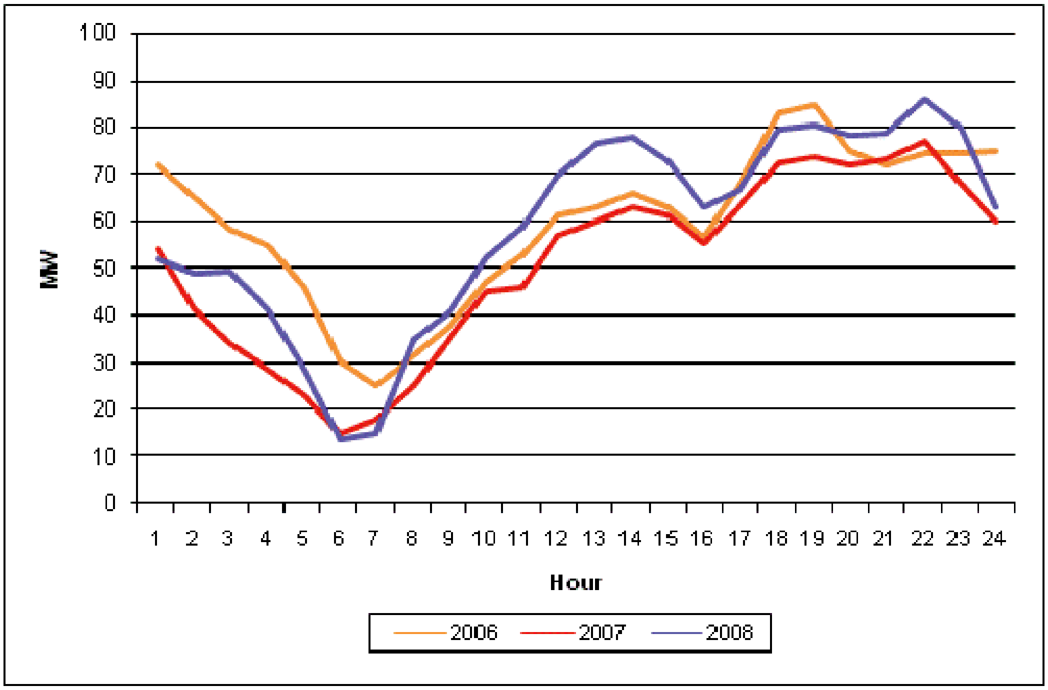

Figure 8-6: New Brunswick average net metered flow by hour of the day, 2006 to 2008.

Table 8-4 shows the average and minimum heat rates of generating resources in New England by generation technology type and input fuel.

Table 8-4
Average and Minimum
Heat Rates for New England Generators, 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	10,900	8,900
	Jet Fuel	12,600	10,500
	No. 2 Oil	16,100	15,500
Steam	Coal	9,700	8,700
	Gas	11,000	10,200
	No. 6 Oil (1%)	10,500	9,200
	Other	10,300	10,000
	Wood	12,400	10,000

8.2 Reserves Appendix

Table 8-5 shows forward-reserve megawatts designated to meet forward-reserve requirements in each reserve zone for 2006 to 2008 categorized by generator technology.[129]

Table 8-5
Forward Reserve Delivered, by Technology Type, 2006 to 2008

Technology Type	2006	2007	2008
Hydro	23.5%	25.0%	23.0%
Non-Fast-Start	4.0%	4.8%	1.5%
Fast Start	72.5%	70.1%	75.5%

Table 8-6 shows the monthly average bilateral trading volume of forward-reserve obligations for 2006 to 2008. The volumes shown do not include prearranged transactions among affiliates occurring at the start of the season.

Table 8-6
Monthly Average Bilateral FRM Obligation Trading Volume, MW, 2006 to 2008

Forward-Reserve Season	Systemwide TMOR	Systemwide TMNSR	SWCT TMOR	CT TMOR	NEMA/Boston TMOR
2006	150	360	37	20	63
2007	0	35	0	0	33
2008	0	269	0	0	16

Figure 8-7 shows monthly average peak-hour reserve margins for TMSR and TMNSR since 2007.

[129] 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.

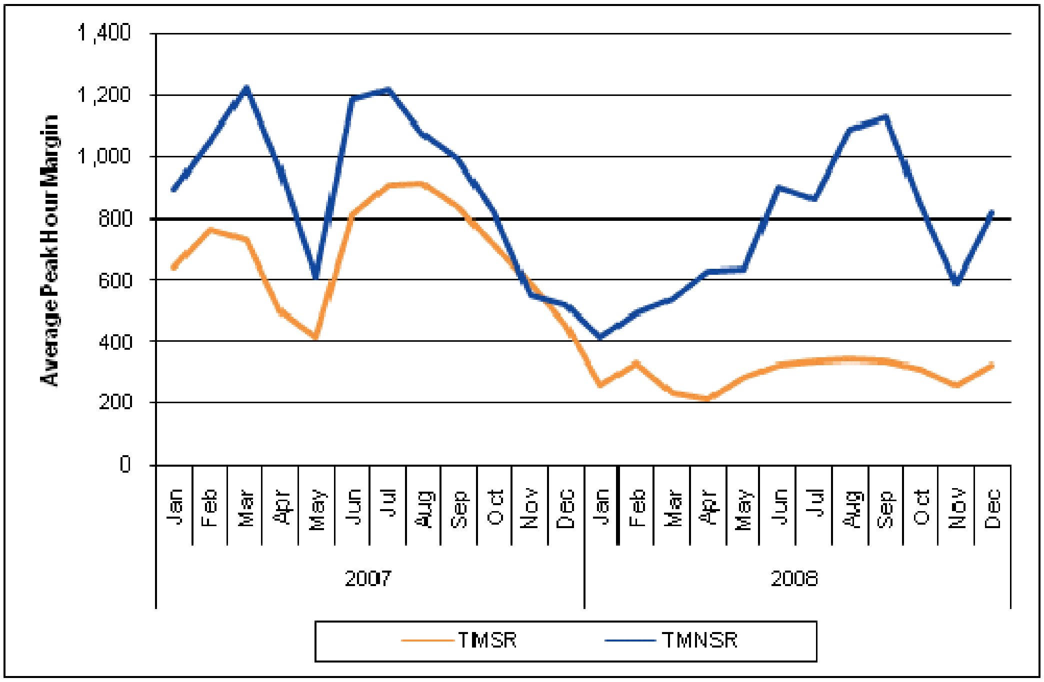

Figure 8-7: Real-time reserve margins, TMSR and TMNSR, peak hour, 2007 to 2008.

Table 8-7 shows penalties assessed by reserve product for 2006 to 2008. Table 8-8 shows failure-to-activate penalties. Total forward and real-time reserve payments and penalties are shown in Table 8-9. The net forward credit equals the forward-reserve payments minus penalties and forward-reserve energy obligation charges.

Table 8-7
Failure-to-Reserve Penalties, 2006 to 2008

Year	Systemwide TMNSR	Systemwide TMOR	SWCT TMOR	CT TMOR	NEMA/Boston TMOR
2006	−$1,947,927	−$83,706	−$344,183	−$60,967	−$748,281
2007	−$3,251,943	−$53,754	−$1,108,773	−$444,735	−$1,542,000
2008	−$3,517,805	−$52,591	−$1,664,859	−$1,536,191	−$911,575

Table 8-8
Failure-to-Activate Penalties, 2006 to 2008

Year	Systemwide TMNSR	Systemwide TMOR	SWCT TMOR	CT TMOR	NEMA/Boston TMOR
2006	$0	$0	$0	$0	$0
2007	−$3,537	$0	$0	$0	$0
2008	−$9,633	$0	$0	$0	−$1,120

Table 8-9
Forward and Real-Time Reserve Payments and Penalties, 2006 to 2008

Year	Fail-To-Activate Penalties	Fail-To-Reserve Penalties	Forward Credit	Forward-Reserve Obligation Charge	Net Forward Credit	Real-Time Credit
2006	$0	−$3,185,063	$41,773,792	−$1,260,211	$37,328,518	$2,922,265
2007	−$3,537	−$6,401,204	$171,893,905	−$1,680,469	$163,808,694	$6,568,714
2008	−$10,752	−$7,683,020	$179,551,242	−$1,543,162	$171,049,377	$16,797,261

Figure 8-8 shows actual claim-10 and claim-30 capabilities over time. The figure shows the impact of performance capping on total system 10-minute and claimed 30-minute reserve capability that began in January 2007.

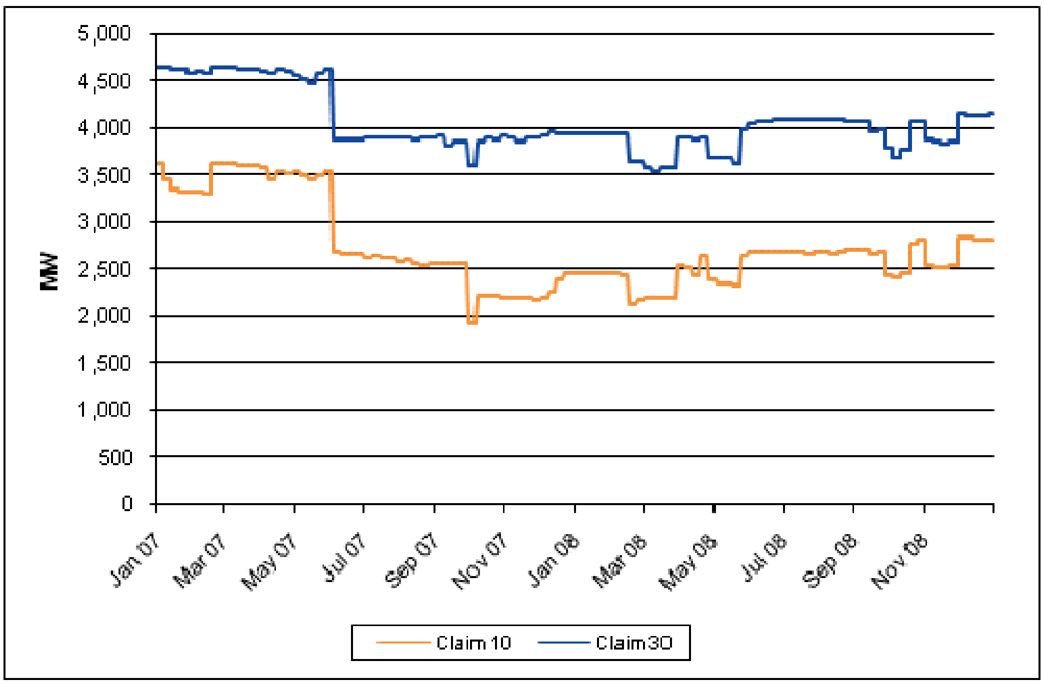

Figure 8-8: Weekly total claim-10 and claim-30 capability, 2008.

List of Acronyms and Abbreviations

Acronyms and Abbreviations	Description
AC	alternating current
ACE	area control error
AMR	Annual Markets Report
ARR	Auction Revenue Rights
Btu	British thermal unit
CB	customer baseline
CC	combined-cycle generator
CONE	cost of new entry
CPS	NERC Control Performance Standard
CPS 2	NERC Control Performance Standard 2
CRBF	Congestion Revenue Balancing Fund
CRS	Congressional Research Service
CT	State of Connecticut, Connecticut load zone, Connecticut reserve zone
DALRP	Day-Ahead Load Response Program
DARD	dispatchable asset-related demand
DOE	U.S. Department of Energy
DOJ	U.S. Department of Justice
EIA	Energy Information Administration (U.S. DOE)
EISA	U.S. *Energy Independence and Security Act of 2007*
EPAct	*Energy Policy Act of 2005*
F	Fahrenheit
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FOB	free on board
FRM	Forward Reserve Market
FTR	Financial Transmission Right
GW	gigawatt
GWh	gigawatt-hour
HHI	Herfindahl-Hirschman Index

Highgate	Vermont–Hydro Quebec Interconnection
HQICC	Hydro-Québec Phase I/II Interface
ICE	Intercontinental Exchange
ICR	Installed Capacity Requirement
IMMU	Independent Market Monitoring Unit
INTMMU	Internal Market Monitoring Unit
ISO	Independent System Operator
kW	kilowatt
kWh	kilowatt-hour
L.L.C.	Limited Liability Corporation
L_{10}	Limit 10
LMP	locational marginal price
LOLE	loss-of-load expectation
LSE	load-serving entity
LSR	local sourcing requirement
MCL	maximum capacity limit
ME	State of Maine and Maine load zone
MMBtu	million British thermal units
MW	megawatt
MWh	megawatt-hour
N-1	first contingency
N-1-1	second contingency
NABS	NEPOOL Automated Billing System
NCPC	Net Commitment-Period Compensation
NE	New England
NEL	net energy for load
NEMA	Northeast Massachusetts and Boston load zone
NEPOOL	New England Power Pool
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)
NPCC	Northeast Power Coordinating Council
NTA	negative target allocation

NY	State of New York
NY-1385	New York 1385 transmission line
NY-AC	New York Alternating-Current Interface
NY-CSC	New York Cross-Sound Cable
O&M	operations and maintenance costs
OATT	*Open Access Transmission Tariff*
ODR	other demand resources
OK	Oklahoma
OP 3	Operating Procedure 3
OP 4	Operating Procedure 4
OP 8	Operating Procedure 8
PER	peak energy rent
PJM	PJM Interconnection, L.L.C.
pnodes	pricing node
PTA	positive target allocation
QUA	Qualified Upgrade Award
QWLI	Quantity-Weighted Lerner Index
RAA	Reserve Adequacy Analysis
RCP	reserve clearing price
RCPF	Reserve Constraint Penalty Factor
RFP	request for proposals
RI	State of Rhode Island and Rhode Island load zone
ROS	Rest-of-System reserve zone
RSI	Residual Supply Index
RSP	Regional System Plan
RTEG	real-time emergency generation
RTLO	real-time load obligation
RTO	Regional Transmission Organization
SCC	seasonal claimed capability
SEMA	Southeast Massachusetts
SMD	Standard Market Design
SOI	show of interest
SWCT	Southwest Connecticut
TMNSR	10-minute nonspinning reserve

TMOR	30-minute operating reserve
TMSR	10-minute spinning reserve
VT	Vermont and Vermont load zone
WCMA	West-Central Massachusetts
WEAF	Weighted Equivalent Availability Factors
WTI	West Texas Intermediate