2007 Annual Markets Report

June 6, 2008

Preface

The Internal Market Monitoring Unit (INTMMU) of ISO New England (ISO) annually publishes an Annual Market Report that assesses the state of competition in the wholesale electricity markets operated by the ISO. The *2007 Annual Markets Report* covers the ISO's most recent operating year, January 1 to December 31, 2007, including 2008 results associated with some key developments in 2007. 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 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 electricity markets. The IMMU is external to the ISO and reports directly to the board of directors. This IMMU's report assesses the design and operation of the markets and the competitive conduct of the market participants.

[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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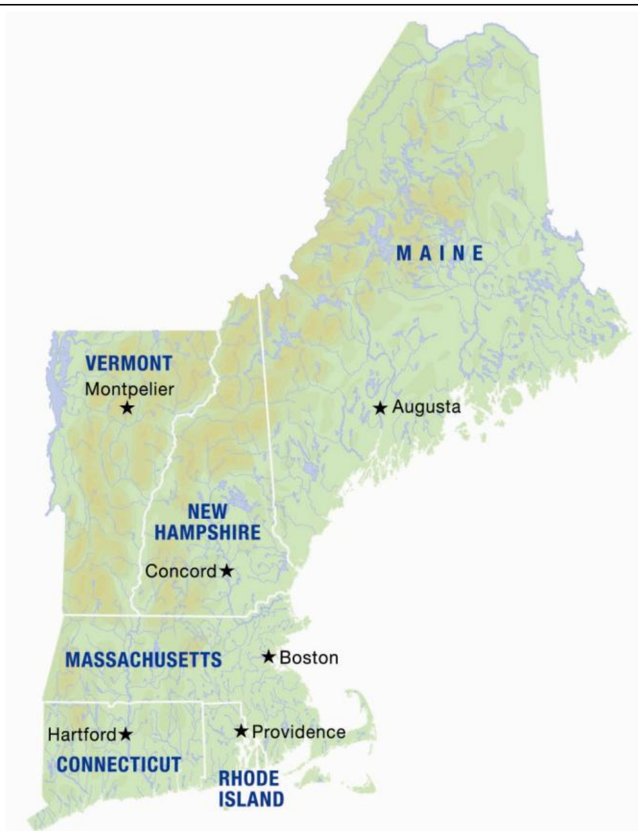
Section 1
Summary of the
2007 Annual Markets Report

Created in 1997, ISO New England (ISO) is the not-for-profit corporation responsible for three main functions:

- Day-to-day operation of New England's bulk power generation and transmission system
- Oversight and administration of the region's wholesale electricity markets
- Management of a comprehensive regional bulk power system planning process

Since February 1, 2005, the ISO has operated as a Regional Transmission Organization (RTO), assuming broader authority over the daily operation of the region's transmission system and possessing greater independence to manage the region's bulk electric power system and competitive wholesale electricity markets. The ISO operates the Day-Ahead and Real-Time Energy Markets, the Forward Capacity Market (FCM), the Regulation Market, the reserve markets, and the annual and monthly auctions of Financial Transmission Rights (FTRs). Figure 1-1 shows key facts about New England's power system and electricity markets.



- 6.5 million households and businesses; population 14 million
- Over 8,000 miles of high-voltage transmission lines
- 13 interconnections to electricity systems in New York and Canada
- More than 32,000 megawatts (MW) of total supply (includes 1,693 MW of demand-resource capacity)
- All-time peak demand of 28,130 MW, set on August 2, 2006
- More than 300 participants in the marketplace (those who generate, buy, sell, transport, and use wholesale electricity)
- $10 billion annual total energy market value (2007)
- More than $1.0 billion in transmission investment made for reliability since 2002; another $4.0 to $7.0 billion planned over the next 10 years
- Approximately $1.0 to $2.0 billion of economic transmission investment to enable renewable resources under study
- Five major 345-kilovolt projects already in various stages of construction and operation

Figure 1-1: Key facts about New England's bulk electric power system and wholesale electricity markets.

This report highlights the state of New England's wholesale electricity markets, presents specific 2007 results, discusses ongoing efforts to improve market performance, and recommends ways to address additional issues facing the region.

Sections 2 to 5 assess the energy, capacity, reserve, and regulation markets. Section 6 assesses reliability costs. The Financial Transmission Rights market and its outcomes are covered in Section 7, and Section 8 evaluates the ISO's demand resources and programs.[3] Sections 9 and 10 highlight market oversight and analysis activities and internal ISO market operations assessments.

Appendices A through C provide supplemental materials. Appendix A provides electricity market statistics at the zonal and monthly levels and additional details of the all-in wholesale electricity cost metric. Appendix B includes offer curves for the Forward Reserve Market. Appendix C provides supplemental cost components of the ISO's *Self-Funding Tariff* and the *Open Access Transmission Tariff* (OATT) and additional data on transmission congestion revenues.[4]

1.1 Key Developments of 2007

The New England wholesale electricity markets continued to perform competitively in 2007, responding to changing supply and demand conditions while supporting reliable grid operations. Several particularly noteworthy developments in 2007 are as follows:

- The Forward Capacity Market, successfully introduced in 2007/2008, improved investment incentives for electric energy supply and demand resources.
- Transmission investment improved the ability to import power into the Norwalk/Stamford area (the southwestern corner of Connecticut) and Boston.
- The region experienced several disruptions to natural gas delivery during 2007 and early 2008 that affected electricity reliability and pricing. The region remains vulnerable to disruptions in the gas infrastructure.

1.1.1 Capacity Investment

By providing long-term investment incentives for supply and demand resources, the Forward Capacity Market complements the existing short-term markets, thus completing the basic structure of the New England wholesale markets. For the FCM, the ISO projects the capacity needs of the power system approximately three years in advance, which allows time for new resources to be built. Through an annual Forward Capacity Auction (FCA), enough qualified resources are purchased to satisfy the region's future needs. The critical task of qualifying resources and potential new projects for participation in the first FCA was completed during 2007. The first auction, covering resources for the 2010/2011 capability year (for June 2010 delivery), concluded successfully on February 6, 2008.[5] As part of the Settlement Agreement approving the FCM, capacity transition payments also were

[3] In the New England Control Area, *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. In electricity markets, demand-resource programs allow participants to modify their electric energy consumption in exchange for payments based on wholesale market prices.

[4] The ISO operates under several FERC tariffs, including the *ISO New England Transmission, Markets, and Services Tariff* (Transmission Tariff) (2005), a part of which is the *Open Access Transmission Tariff* (OATT), and the *Self-Funding Tariff*. These documents are available online at http://www.iso-ne.com/regulatory/tariff/index.html.

[5] A capability year is a one-year period beginning June 1 of one year and ending May 31 of the following year.

approved for all installed capacity (ICAP). The payments began in December 2006 and will continue until May 2010.[6]

1.1.2 Transmission Investment

Increased transmission capacity helps power move more freely throughout the system, thereby improving competition and reducing the overall cost of the generation needed to meet the bulk power system's total loads. In 2007, major progress was made on projects to strengthen the transmission system. In Connecticut, Phase 1 of the Southwest Connecticut (SWCT) 345-kilovolt (kV) Reliability Project was completed, expanding transmission in the Norwalk/Stamford area. The completion of Phase 1 improved reliability and helped equalize the energy price in Norwalk/Stamford with that in the rest of Connecticut and at the Hub.[7] Phase 2 is scheduled to be completed no later than December 2009 and will improve flow between SWCT and the rest of Connecticut. Transmission improvements in the Boston area, which increased the Boston import limit from 3,600 megawatts (MW) to a range of 4,500 MW to 4,800 MW, also helped improve regional reliability.

Transmission improvements also reduce the need for cost-of-service Reliability Agreement contracts with individual generators in certain load pockets, which are more expensive than competitive resources outside those load pockets.[8,9] These payments to individual generators in load pockets cannot be hedged and are not subject to competition.

1.1.3 Natural Gas Infrastructure

In 2007, New England electricity markets demonstrated their vulnerability to disruptions in the natural gas infrastructure. Natural-gas-fueled resources, including dual-fueled units, generated 42% of New England's electricity in 2007. On December 1, 2007, two major generators in Maine were lost because of a mechanical failure at the Sable Island production fields (offshore Nova Scotia). The losses led to a suspension of gas delivery and caused approximately 1,200 MW of generator reductions in Maine. The supply reductions, in combination with higher-than-forecast loads, led to the implementation of ISO Operating Procedure 4 (OP 4), *Action during a Capacity Deficiency*.[10]

As a result of the event of December 1–2, the gas pipeline companies significantly improved communications with the ISO. Although six similar events occurred afterward—between December 2007 and March 2008—none required the implementation of OP 4. In five of these six events, timely communication allowed the ISO to commit additional oil units to prevent a capacity deficiency. In the sixth event, no ISO action was necessary.

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[6] *Order Accepting in Part and Modifying in Part Standard Market Design Filing and Dismissing Compliance Filing* (hereafter cited as SMD Order), 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 Hub is a collection of locations for which the ISO calculates and publishes prices. The Hub price is intended to represent an uncongested price for electric energy.

[8] Long-term contracts providing for reliability are known as Reliability Agreements; short-term payments for single-day commitments of out-of-merit generators are called daily reliability payments.

[9] *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).

[10] ISO New England's Operating Procedure 4 is available online at http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html.

1.2 Key Market Results

New England's wholesale markets have entered a new phase with the introduction of the Forward Capacity Market. In 2007, capacity costs were a larger component of total wholesale electric energy costs than in previous years in both absolute and relative terms. Figure 1-2 shows the all-in cost metric for wholesale electric energy that load-serving entities (LSEs) with real-time load obligation paid in 2005 through 2007.

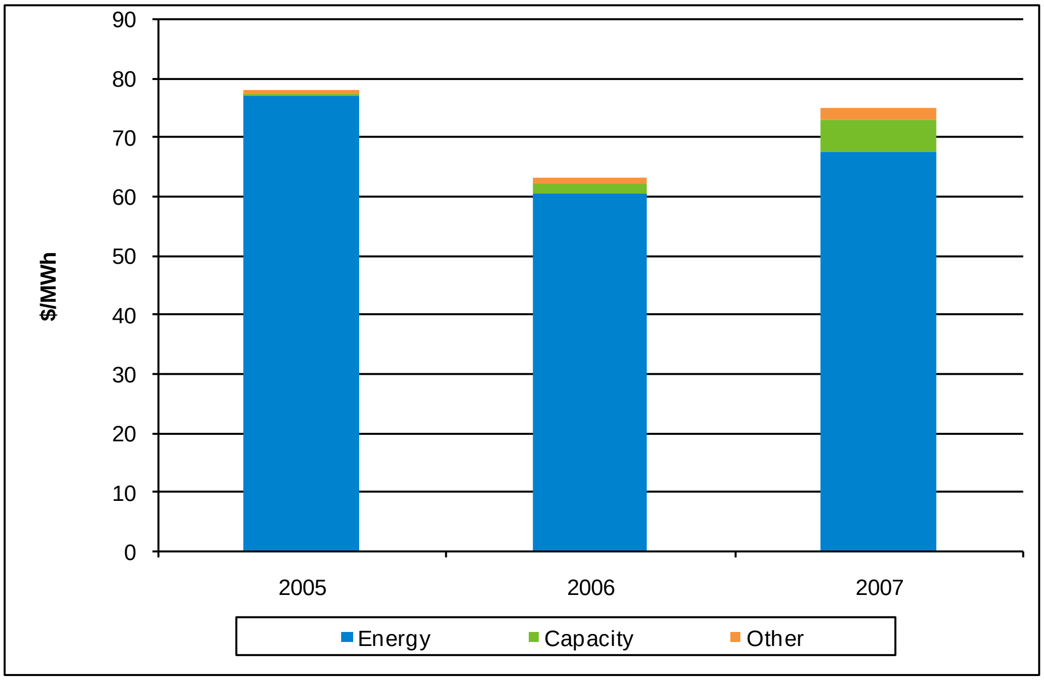


Figure 1-2: All-in wholesale electric energy cost metric for 2005 to 2007.

The all-in cost for serving load in New England fell in 2006 but rose in 2007 primarily as a result of higher energy costs and the introduction of capacity transition payments. Before the capacity market Settlement Agreement and the beginning of the FCM transition payments, capacity prices were determined by a deficient capacity market with low but highly volatile prices that did not provide appropriate allocative signals. In 2006, capacity could be bought in the ICAP supply auction at an average price of $0.205/kW-month. The transition payment specified by the Settlement Agreement was fixed at $3.05/kW-month during 2007. This was offset by a reduction of $214 million in net Reliability Agreement payments. Table 1-1 shows the detailed breakdown of the wholesale load cost metric for 2006, 2007, and the year-to-year change. The 2007 energy cost rose from $60.63/MWh in 2006 to $67.59/MWh in 2007, an 11% increase. The cost of capacity rose from an average of $1.62/MWh to $5.38/MWh, and the category "Other" increased from $0.93/MWh to 2.11/MWh. The energy and capacity components account for 90% of the total change in the all-in cost.

Table 1-1
Change in All-In Wholesale Electric Energy Cost Components, 2006 to 2007, $/MWh

Component	2006	2007	Change
Energy	60.63	67.59	6.97
Capacity	1.62	5.38	3.76
Other	0.92	2.11	1.19
Total	**63.17**	**75.08**	**11.92**

The electric energy portion of the all-in costs was driven by rising fuel costs and higher consumption of electricity during 2007. In 2007, natural gas resources set price in New England 74% of the time. Figure 1-3 illustrates the close relationship between natural gas prices and electricity prices. The figure demonstrates several issues. First, electric energy costs are tightly linked to the price of natural gas. As natural gas prices rise, electricity prices also rise. Second, oil prices have been growing faster than natural gas prices. Thus, when oil-fueled units are needed to meet summer peak loads, electricity prices are higher than the cost of a natural-gas-fired generator. This caused the summer 2007 gap between electricity prices and natural gas costs shown in Figure 1-3. Overall, the tight link between the marginal fuel and electricity prices is consistent with a competitive market in which prices are determined by marginal costs.

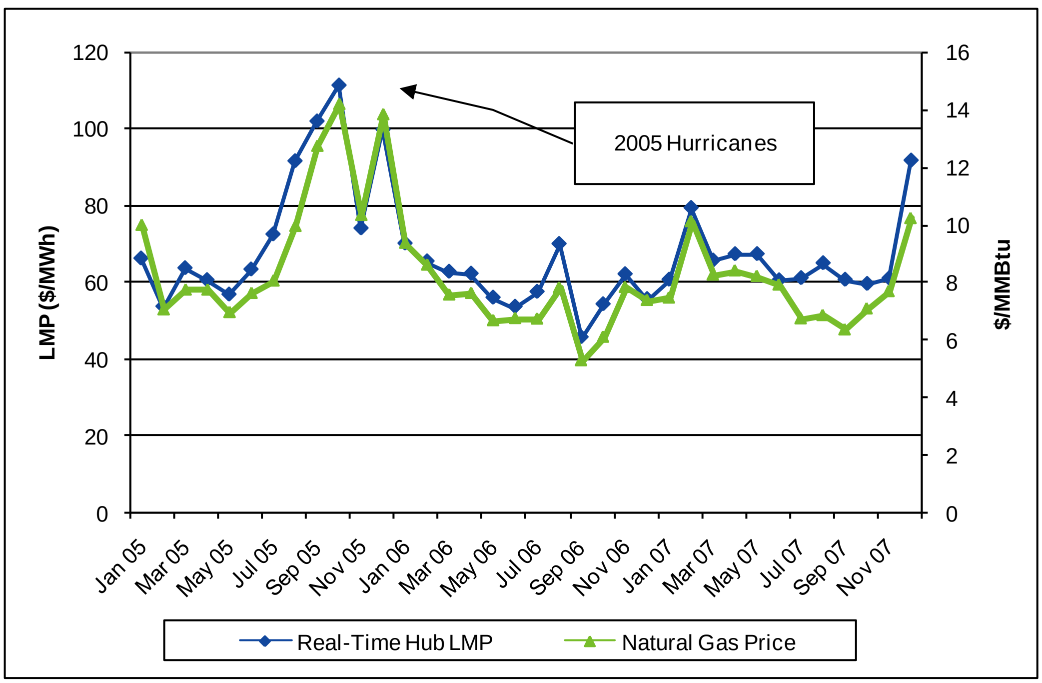


Figure 1-3: Electricity prices and natural gas prices.

Net revenues for New England resources improved significantly in 2007. This is a result of higher electric energy prices and the introduction of the $3.05/kW-month capacity transition payments. FERC has developed standard metrics to measure net revenues for a representative combined-cycle generator and a representative combustion turbine, both gas fired. The net revenue of the representative combined-cycle generator in 2007 increased 51% from the 2006 estimate to

$13.10/kW-month. For the representative combustion turbine, the estimated net revenue increased 96% between 2006 and 2007 to $7.80/kW-month. If transition payments were excluded from both years, the net revenues still would have increased 16% and 20%, respectively, for combined-cycle and combustion turbine generators.

The increase in net revenues from higher capacity payments was consistent with the design objectives of the FCM. The remaining increase in net revenues compared with 2006 levels, after accounting for higher capacity costs, is within the range of variability expected from the underlying supply and demand conditions. It is too soon to evaluate the impact of these changes in short-term revenues on long-term investment decisions, such as generation project developments or retirements.

1.3 Market-by-Market Highlights

This section presents the main 2007 results for each of New England's wholesale markets for electric energy, capacity, reserves, regulation, and financial transmission rights. Out-of-market compensation for reliability also is summarized.

1.3.1 Electric Energy Markets

The factors that most affected the electric energy markets in 2007 included the increased cost of fuel, reduced transmission constraints, and a lower peak demand yet higher total yearly electric energy consumption.

1.3.1.1 2007 Fuel Prices

The primary input to electricity production is fuel, and fuel prices increased in 2007. The price for liquid fuels, such as diesel and No. 6 oil, increased more rapidly than natural gas prices. Both these patterns—the general increase in fuel prices and the increasing disparity between the prices for liquids and natural gas—continue trends from the past few years. This is illustrated in Figure 1-4.

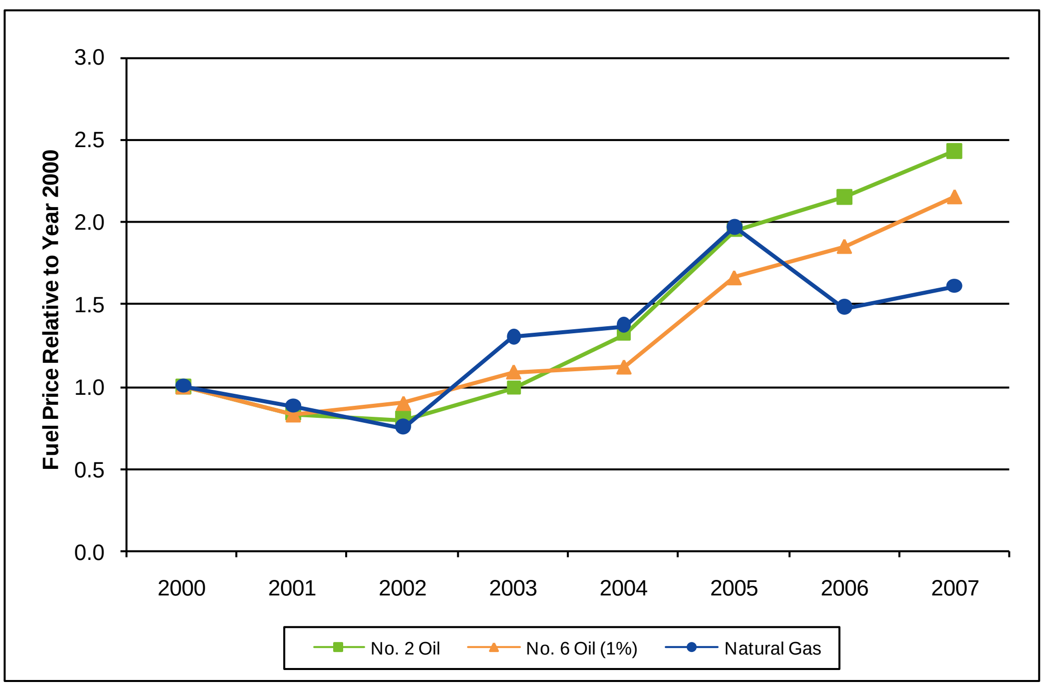


Figure 1-4: Growth in fuel prices relative to year 2000 prices.

The ISO historically has calculated a "fuel-adjusted" electricity price using a simple, limited methodology. The analysis uses the year 2000 as a base and normalizes the locational marginal price (LMP) of the marginal unit in each five-minute interval to fuel prices in 2000. This methodology assumes that the same marginal units would be dispatched in both the base year of 2000 and the current year being evaluated. While this methodology has been informative, it can become less accurate as electricity demand, generation capacity, relative fuel prices, and the mix of resources change. For example, the recent divergence of relative fuel prices, as illustrated in Figure 1-4, is the type of change that would lead to different units being dispatched at the margin and, more importantly, potentially different fuels firing the marginal unit. The ISO intends to improve the estimation of fuel-adjusted prices in future years to account for all factors more appropriately.

Electric energy prices appear to be normal when adjusted for fuel prices. The fuel-adjusted price of electric energy in 2007 of $45.15/MWh was $2.51/MWh higher than in 2006. In comparison, the average fuel-adjusted price from 2000 to 2006 was $45.01/MWh. Actual unadjusted average electric energy prices rose from $62.74/MWh in 2006 to $69.57/MWh in 2007. This increase was paralleled by an 8.8% increase in natural gas prices and a 16.2% increase in the price of 1% sulfur No. 6 oil.

The increase in the fuel-adjusted price is within the range of the estimation uncertainty. Additionally, the size and direction of the change are consistent with the effect of increased energy demand in 2007. The ISO estimated the effect of increased demand by applying the increased demand to representative supply curves. Average hourly energy demand increased by 279 MW, yielding estimates ranging from a low of $1.29/MWh to $4.96/MWh. The observed increase in the fuel-adjusted energy price of $2.51 (5.8%) falls well within this range. Therefore, changes in the market price are consistent with the shifts in the underlying demand and supply conditions. More details of this analysis are provided in Section 2.4.2.

1.3.1.2 Transmission Improvements

Transmission improvements reduced congestion in the Norwalk/Stamford area of Southwest Connecticut. The maps in Figure 1-5 show average annual real-time nodal prices for 2006 and 2007. The maps show that the chronic congestion into the Norwalk/Stamford area eased from 2006 to 2007, indicated by the lack of the red coloring in the 2007 map compared with the concentrated red corner in the 2006 map. The map also reflects that prices over all New England generally were higher in 2007 (indicated by the predominance of the yellow-green color in the 2007 map compared with the more blue-green color in the 2006 map). As mentioned, this was largely due to higher fuel prices in 2007 than in the previous year.

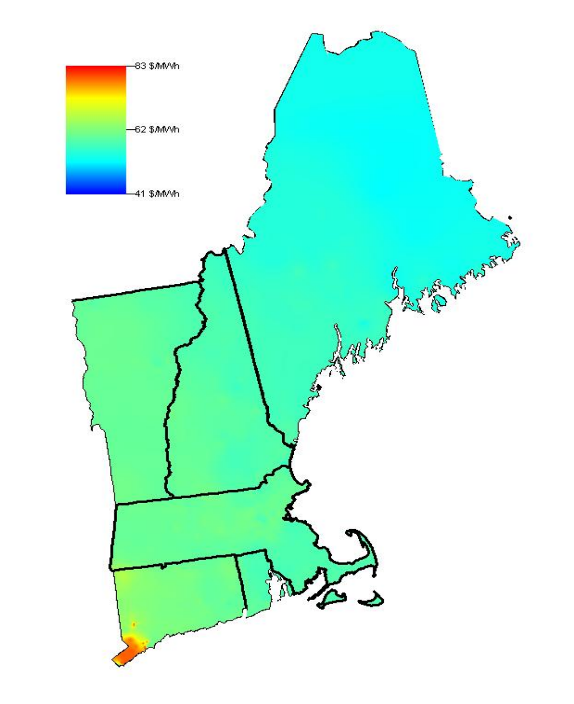
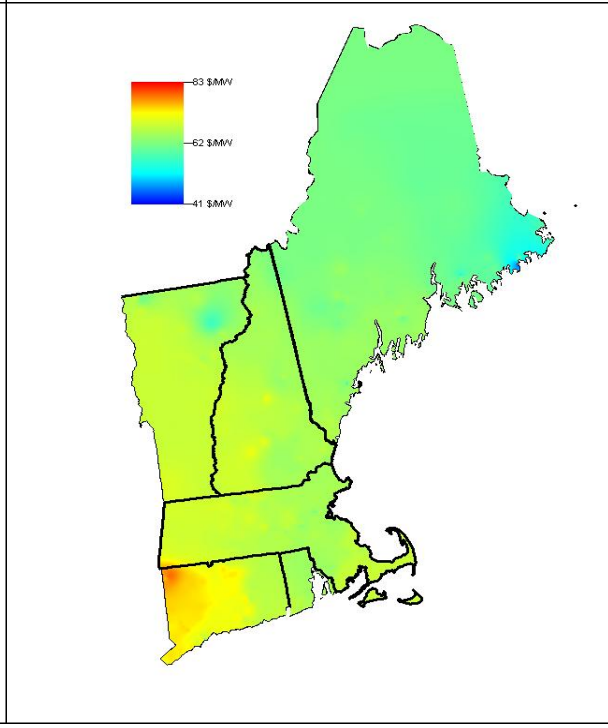
2006	2007
	

Figure 1-5: Average real-time nodal prices, 2006 and 2007, $/MWh.

Average nodal prices in the Norwalk/Stamford area of Connecticut also were reduced by the elimination of the Peaking-Unit Safe-Harbor (PUSH) threshold in June 2007. FERC established the PUSH threshold to give generators in designated congestion areas (Connecticut and Northeast Massachusetts and Boston [NEMA/Boston]) an opportunity to recover capital costs. PUSH allowed units with low capacity factors to offer into the market at prices above marginal cost.[11] FERC terminated the PUSH threshold with the advent of the FCM and transition payments.

1.3.1.3 2007 Demand

Demand in 2007 was marked by two significant features: a lower peak than in 2006 and a higher yearly total consumption. The record peak demand of 2006 was attributable to extraordinary weather. The 2007 peak demand of 26,134 MW occurred with temperatures more consistent with long-term averages.[12]

The long-run trend of a decreasing weather-normalized load factor continued, although the actual (unadjusted) load factor increased.[13] When normalizing for weather, peak hourly demand rose faster than average demand from 2006 to 2007, resulting in a lower load factor. The actual, unadjusted load

[11] Under PUSH, affected units could offer into the market at prices above marginal cost, which if accepted, sometimes raised the Connecticut price above levels elsewhere in the region. See Section 6 for more information about PUSH thresholds.

[12] The system peak for 2006 was driven by a period of unusually hot and humid weather in late July and early August. Other than these periods, temperatures in 2006 were somewhat mild relative to long-term averages, which when also accounting for retail price increases, resulted in a decrease in average load for the year.

[13] The *load factor* is the ratio of the average hourly demand during a year to the peak hourly demand. *Weather-normalized* results are those that would have been observed if weather were the same as the long-term average.

factor increased between 2006 and 2007. This is because the actual peak load decreased while the average load increased between 2006 and 2007.

The net energy for load (NEL) supplied to the system in 2007 increased 1.9% from the 2006 level.[14] Figure 1-6 shows yearly total NEL for 1980 through 2007. After a decrease in NEL from 2005 to 2006, aggregate energy consumption increased in 2007 following historical patterns. The decline in energy use in 2006, both actual and weather normalized, was a response to the large increases in natural gas and electricity prices.[15]

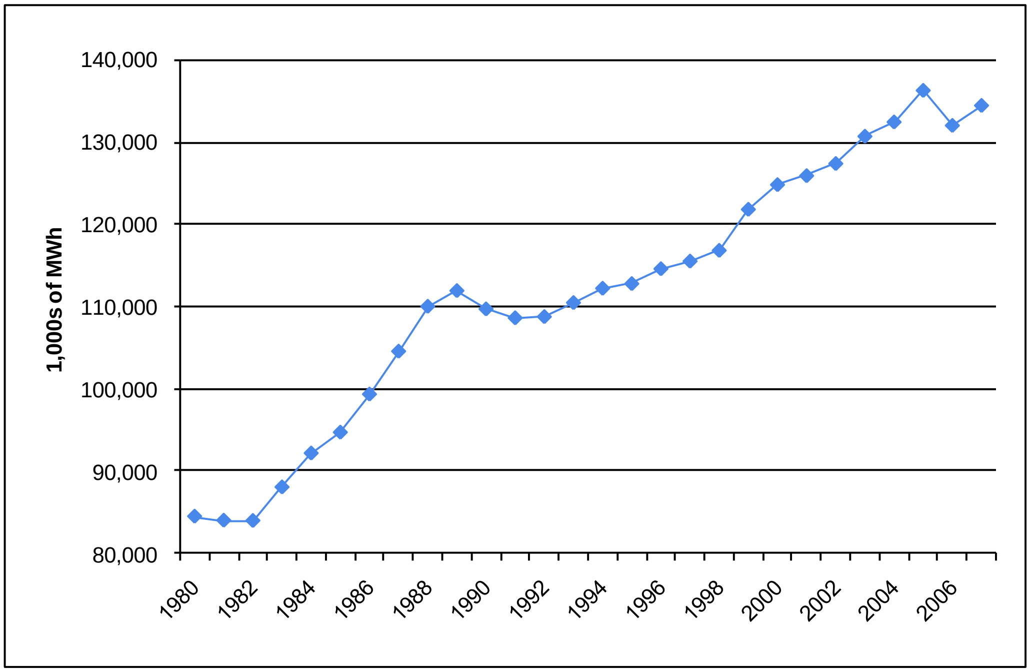


Figure 1-6: New England actual net energy for load, 1980 to 2007.

1.3.1.4 Competition Analysis

The ISO uses three primary metrics to assess competition in the energy markets:

- The *Herfindahl-Hirschman Index* (HHI). This is a measure of market concentration based on generating capacity. An HHI below 1,000 indicates a low concentration of market power.
- A price mark-up model, or *competitive benchmark price* model, which models and compares prices based on competitive offers with prices based on actual offers. The difference also is used to estimate an index called the *Quantity-Weighted Lerner Index.* See Section 9.4.4 for more details.
- The *Residual Supply Index* (RSI). This index measures the hourly percentage of load in megawatt-hours (MWh) that can be met without the largest supplier. Such suppliers are termed "pivotal" and can affect market prices.

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

[15] The decline of energy use in 2006 is discussed in the ISO's *2006 Annual Market Report* (AMR06) (June 11, 2007), available online at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html.

On the basis of these three metrics, the 2007 analyses, like the 2006 analyses, confirm that the wholesale electricity markets in New England continue to be competitive. However, the level of competition was significantly reduced in some typically constrained areas. The HHI in 2007 for New England markets as a whole was 670, relatively unchanged since 2004 and well below the benchmark set by the U.S. Department of Justice (DOJ) for raising market power concerns.[16] But the HHI calculated for individual load zones indicated highly or moderately concentrated markets.[17] The ISO's mitigation thresholds for constrained areas are designed to alleviate market power in instances where transmission constraints expose the market to conditions of high market concentration. The Quantity-Weighted Lerner Index of 2%, in the absence of congestion, is in line with competitive conditions and past results in New England. The Residual Supply Index shows that in only 1.3% of total hours during 2007 were there pivotal suppliers.

1.3.1.5 Energy Market Conclusions

The electric energy markets in the New England region continued to work competitively in 2007. These markets have adjusted effectively to rising fuel prices and higher electric energy consumption. The introduction of new transmission successfully improved reliability in the Norwalk/Stamford area and, combined with the elimination of the PUSH treatment, reduced LMPs in that area. Further transmission upgrades scheduled for Southwest Connecticut and the rest of Connecticut should provide similar benefits. The competitive analyses further confirm that the electric energy markets continued to function competitively in 2007.

1.3.2 Reliability Costs

At times, resources that are needed for reliability but cannot recover their costs through the energy and ancillary services markets require out-of-market compensation. These resources receive either daily reliability payments (i.e., "uplift") or payments through cost-of-service Reliability Agreements.[18] Daily reliability payments compensate resources needed during particular hours for first-contingency and second-contingency protection, voltage reliability, or out-of-merit operation of special-constraint resources.[19] Reliability Agreements compensate eligible resources with monthly fixed-cost payments for maintaining capacity that provides reliability services and for ensuring that these resources will continue to be available. These contractual arrangements are subject to approval by FERC.

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[16] U.S. Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines*, issued April 2, 1992, and revised April 8, 1997. Available online at http://www.usdoj.gov/atr/public/guidelines/hmg.pdf.

[17] 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). Refer to Section 2.1 for a more detailed definition of load zones. The New England Control Area also is divided into subareas and reserve zones, explained more fully in Section 2.3.6 and Section 4.1, respectively.

[18] Daily reliability payment is another term for Net Commitment-Period Compensation (NCPC) credit, which is paid to resources for providing operating or replacement reserves 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 electric 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* (2005), available online at http://www.iso-ne.com/regulatory/tariff/sect_3/.

[19] 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. A *special-constraint resource* is committed at the request of a transmission owner or distribution utility. Throughout this document, the term *distribution payments* is used as a synonym for payments made to special-constraint resources.

1.3.2.1 Daily Reliability Payments

Figure 1-7 shows total daily reliability payments by month for 2006 and 2007. January and February 2007 payments were lower than in 2006, while payments sharply increased in March 2007. The March 2007 rise was at least partly the result of the increasing price of No. 6 oil. Reliability resources burning No. 6 oil became increasingly expensive as a result. Overall, total daily reliability payments increased by only 6% between 2006 and 2007, despite the marked rise in March 2007.

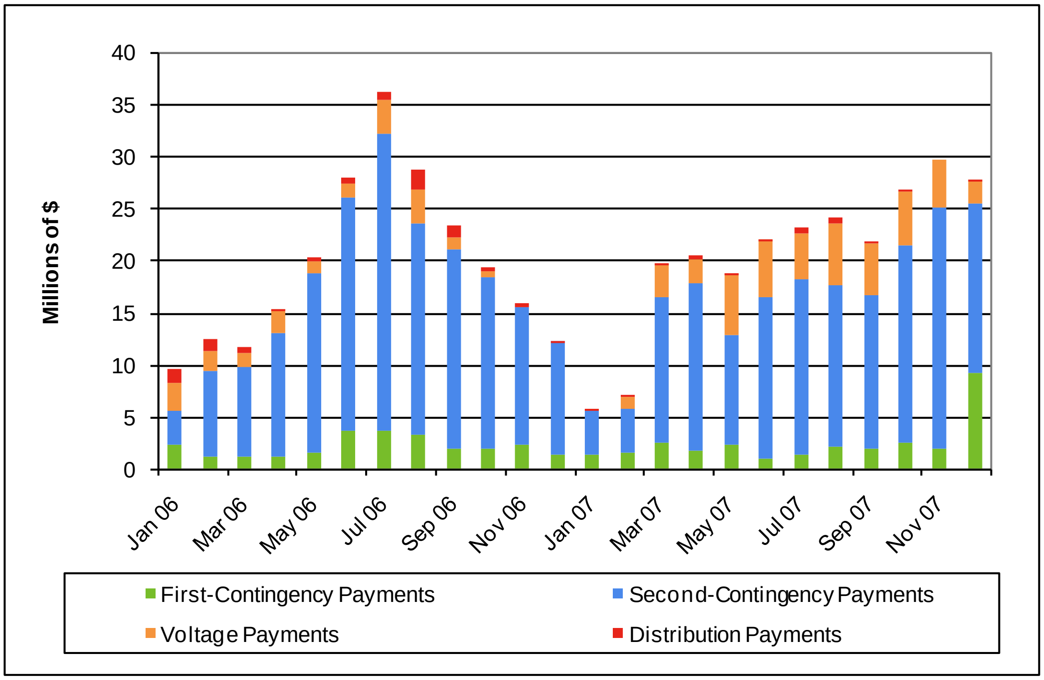

Figure 1-7: Daily reliability payments by month, January 2006 to December 2007.

In response to the introduction of capacity transition payments and FCM, the ISO conducted a deeper analysis of 2007 daily reliability payments. This analysis confirmed that during 2007, more than 50% of daily reliability payments were made to two resources. Other years show a similar pattern of concentration. These two resources did not trigger daily reliability payment mitigation thresholds during 2007. Thus, despite the existing mitigation thresholds for daily reliability payments, a few resources have been able to garner net revenues from out-of-market daily reliability payments in the absence of competition of approximately $3/kW-month. This suggests that the mitigation thresholds for daily reliability payments need to be reexamined. See Section 9.3.3 for further details.

1.3.2.2 Reliability Agreements

Compared with 2006, the amount of capacity operating under a Reliability Agreement declined by 2,640 MW in 2007. Net Reliability Agreement payments declined 59%, from $348 million in 2006 to $143 million in 2007, which represents significant progress for New England. The drop was the result of transmission improvements, especially into NEMA; economic signals provided by the recently revised Forward Reserve Market; and the recently implemented FCM transition payments. While transmission infrastructure improvements have reduced the need for Reliability Agreements, market reforms have improved market incentives, making market-based rates more attractive to resources.

1.3.3 Forward Capacity Market

The year 2007 marked the first full year of transition to the Forward Capacity Market. Three primary FCM results occurred during 2007 and early 2008:

- Capacity market transition payments of $3.05/kW-month were made to all ICAP resources in accordance with the FCM Settlement Agreement.
- The ISO evaluated over 13,000 MW of new capacity projects submitted in the qualification stage for the first Forward Capacity Auction.
- The first FCA was successfully completed in February 2008 with competitive offers from 6,102 MW. A total of approximately 1,813 MW of new resources was selected.

The $3.05/kW-month transition payments have motivated a large increase in participation in ISO demand-resource programs, as discussed in more detail in Section 3.5.

Nearly 74% of the 13,000 MW of new capacity projects submitted during the first FCA qualification process consisted of demand resources, contributing nearly 20% of the total new capacity selected in the first auction. The FCM introduced the possibility of composite offers, which allow summer-only demand resources to make joint offers with winter-only capability from other resources. For the first qualification process for the first FCA, 1,224 MW of composite offers were submitted.

Qualified new capacity participating in the first FCA totaled 6,102 MW. Approximately 18% of the capacity competing in the auction was surplus above New England's total requirement of 32,305 MW. The auction selected approximately 1,813 MW of new supply and demand resources. Of the new resources chosen, 1,188 MW represent new demand-resource projects, and 626 MW represent new supply projects. The auction closed at the administrative floor price of $4.50/kW-month (see Section 3.7). This capacity will be in service by June 2010.

Although the capacity obligation period has not yet started and many steps remain to achieve full implementation of the FCM, the successful implementation of the Forward Capacity Auction represents a significant achievement for the ISO. One goal of the FCM was to ensure adequate competition from new resources in the capacity market by holding the auction well in advance of the delivery or obligation period. The evidence to date supports the conclusion that the market succeeded in this regard. The market rules still need to be conformed to FCM-related changes to complete the FCM implementation. A second goal of the FCM was to incorporate demand resources in the capacity markets. The level of demand-resource participation, including composite offers that allow for seasonal resource participation, show that the market has been successful in attracting demand resources.

1.3.4 Reserve Markets

The ISO compensates resources for providing operating reserves through two means: the locational Forward Reserve Market (FRM) and locational real-time reserve pricing. The locational Forward Reserve Market was designed to induce long-term investment in reserve capability. The FRM auctions are held twice per year for a service period beginning one month after the auction. Locational real-time reserve pricing, in contrast, was designed to complement the short-term electric energy markets. Locational real-time reserve pricing is co-optimized with energy and transmission use every five minutes.

1.3.4.1 Locational Forward Reserves

The year 2007 marks the first full year of operation for these markets in their current form, which procures forward reserves and pays real-time reserve prices for individual reserve zones.[20] Before October 2006, the Forward Reserve Market was not locational, and real-time reserve pricing did not exist in New England when locational markets and Standard Market Design (SMD) were introduced in 2003.

A primary goal of the FRM is to encourage the retention of and in some areas an increase in the level of resources capable of providing reserves. Overall participation in the FRM auctions has increased. The total supply offered into the winter 2007 auction was 390 MW, or 14% greater than for the winter 2006 auction. The supply increases were concentrated in NEMA/Boston and Connecticut. NEMA/Boston offers increased by 39%. Connecticut offers (combined with Southwest Connecticut offers) increased by 44%. The participation results are encouraging for these markets. However, evaluating the market results still is premature.

The FRM design uses several fixed parameters that determine reserve requirements and threshold prices. The threshold price is intended to preselect resources with capacity factors less than 2.5% (i.e., resources designed to provide reserve). Market results indicate that the threshold price often is lower than the LMP. This allows forward-reserve resources to be dispatched for electric energy rather than being used for reserve. This outcome is inconsistent with the market design objectives, and the threshold-price methodology should be reviewed. In the forward-reserve auction, the quantity of reserves required for the Rest-of-System (ROS) reserve zone is based on several parameters, one of which is the expected reliability of resources, which is based on an estimate of the number of failures of fossil-fueled fast-start units. However, hydro resources that historically have had higher-than-average reliability records often clear the auction in the ROS reserve zone. Because of these market results, the parameters used to set the ROS reserve-zone requirement also should be reviewed.

1.3.4.2 Real-Time Reserve Pricing

In real time, resources are dispatched in a least-cost manner to meet simultaneously the system's requirements for electric energy and reserve, while respecting transmission-security constraints. Reserve prices are calculated using the electric energy offer prices and reserve-constraint penalty factors (RCPFs) when applicable—there are no real-time reserve offers.[21]

Real-time reserve prices are expected to be zero most of the time because sufficient reserve usually is available based on normal economic dispatch; therefore, no additional costs are incurred to provide reserves. Nonzero reserve prices occur when resources are redispatched to meet reserve requirements. Real-time reserve pricing results match the expected pattern of relatively infrequent positive prices. In 452 hours during 2007, positive reserve-clearing prices occurred in at least one reserve zone.

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[20] *Reserve zones* are geographic areas that have specific reserve requirements necessary for reliable operations of the system. The ISO has four reserve zones: NEMA/Boston, Connecticut (CT), Southwest Connecticut (SWCT), and the rest of the system (Rest-of-System; ROS). The New England Control Area also is divided into subareas and load zones, explained more fully in Section 2.3.6 and Section 2.1, respectively.

[21] *Reserve-constraint penalty factors* are the rates, in $/MWh, that are used within the real-time dispatch and pricing algorithm to reflect the value of operating-reserve shortages. RCPFs are more fully defined in Market Rule 1, Section III.2.7, available online at http://www.iso-ne.com/regulatory/tariff/sect_3/.

1.3.4.3 Performance Capping

In conjunction with the revised reserve markets, the ISO implemented additional performance monitoring and auditing for resources with off-line reserve capability. Beginning in January 2007, failure to perform, either during normal operations or during audits, resulted in a cap being placed on the megawatt value of reserve credit allowed to the nonperforming resource. Off-line 30-minute reserve capability fell from a systemwide average of 4,621 MW in December 2006 to an average of 3,907 MW in December 2007. Off-line 10-minute reserve capability fell from a systemwide average of 3,262 MW in December 2006 to an average of 2,139 MW in December 2007. The performance auditing and capping program has improved the measurement of reserve capability. This ensures that resources are paid for reserve only to the extent of their true capability. Better measurement also improves reliability by giving system operators more accurate knowledge of the reserve margins.

1.3.4.4 Reserve Market Conclusions

The Forward Reserve Market cleared megawatts of reserve obligation in reserve zones that typically have been short. While some reserve zones continue to be short, the quantity of offers has increased in response to market clearing. Real-time reserve pricing has performed effectively to create additional reserve through redispatch and to compensate reserve providers for their opportunity costs of backing down resources.

The ISO should reevaluate and fine-tune the parameters used to determine reserve requirements and threshold prices. The ISO has begun to evaluate the values for one of these parameters, the reserve-constraint penalty factor. Performance capping is working well and has improved both reliability and market performance through more accurate measurement.

1.3.5 Regulation Market

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. 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 bulk power system. The Regulation Market is the mechanism for selecting and paying generation needed to manage this system balancing.

On October 1, 2005, the ISO implemented modifications to the Regulation Market.[22] The market changes included adding a service payment and improving the calculation of opportunity costs. In January 2007, the ISO implemented further changes. Specifically, the 2007 changes improved the selection of regulation resources to meet the market design objective of minimizing costs.

The regulation provided by the market allowed the ISO to exceed the North American Electric Reliability Corporation's (NERC's) primary regulation metric, *Control Performance Standard 2*, which is NERC's primary measure for evaluating control performance.[23] On the market side, total costs fell from $78.1 million in 2006 to $43.8 million in 2007.

[22] See the ISO's 2003 through 2005 *Annual Markets Reports* for a detailed description of the SMD Regulation Market, available online in the ISO archive at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html.

[23] NERC's mission is to ensure the reliability of the bulk electric system in North America. For more information on NERC's Control Performance Standard 2, see the NERC Web site at http://www.nerc.com/~filez/rs.html.

In 2007, the Regulation Market performed well both in terms of reliability and market efficiency. The 44% drop in market costs provides early but reassuring evidence that the reforms were effective in improving market performance.

1.3.6 Financial Transmission Rights Market

A Financial Transmission Right is a financial instrument that entitles the holder to a stream of revenues (or obligates them to a stream of costs). This stream of revenues or costs is based on the difference between the day-ahead congestion component of the locational marginal price at each of the nodes that defines the FTR. The market performance of Financial Transmission Rights can be evaluated from two functional perspectives—as a cost hedge for transmission congestion or as a financial arbitrage instrument.

An appropriate metric for FTR market competitiveness as an arbitrage instrument is the path profitability of FTRs. This is defined as the difference between the cost of acquiring the FTR (i.e., the auction cost) and the revenue generated or the costs obligated by the FTR. In a competitive market, the expected profits of a risk-neutral participant holding an FTR as an arbitrage instrument should approach zero. As in 2006, the FTR auction revenue ($123 million) was close to the day-ahead congestion revenue ($130 million) in 2007. Moreover, the average monthly profits for FTRs were 5 cents/MWh for on-peak FTRs and 1 cent/MWh for off-peak FTRs. These results are in accordance with a competitive market for FTRs used as arbitrage instruments.

The performance metric of an FTR as a hedge against congestion costs is whether the FTR provides the congestion cost certainty the buyer is expecting, defined by full funding in the year-end FTR settlements. In the monthly FTR settlements, funds are collected from the day-ahead and real-time congestion revenues and paid to FTR holders on the basis of their FTR amount and direction. The monthly process is followed by a year-end "true up" with any available remaining funds. Full funding is measured by comparing the amount paid through the monthly and year-end FTR settlement with the actual day-ahead congestion paid in the energy market settlement. For example, if an FTR holder received $50 for the year, but had an energy transaction matching the FTR size and direction that required payment of $100 in day-ahead congestion, the FTR holder would have received 50% of the hedge. Any single month could have a shortfall or surplus. The Congestion Revenue Balancing Fund (CRBF) accrued positive amounts during four months in 2007.[24] The four months of surpluses were not enough to make up the shortfalls in the remaining eight months. The FTRs did not provide a full hedge of day-ahead congestion costs. Of the $191.8 million owed to FTR holders, $182.0 million, or 95%, was distributed after the year-end settlement.

Monthly shortfalls and surpluses arise from differences in outage assumptions or transfer limits between the different markets associated with the FTR settlement process. Such differences can be caused by unexpected transmission outages, generation outages, or unexpected load patterns. The ISO forecasts the cumulative effect of the outages and other changes so that the amount of FTRs awarded will be as accurate as possible and shortfalls and surpluses both will be minimized.

[24] The *Congestion Revenue Balancing Fund* is a mechanism for tracking congestion revenues, FTR payments, and monthly surpluses and shortfalls. Year-end surpluses in the CRBF are allocated to FTR holders that received less than 100% of the amount they were owed based on their monthly FTR allocation amounts during the year.

Beginning in December 2007, the PJM Interconnection encountered several FTR payment defaults.[25] Such default risks fundamentally create a moral hazard because every FTR represents a potential financial obligation that the holder can avoid through default when the loss of collateral is less costly than payment of its FTR obligation. The default leaves other participants to bear the consequence of the defaulting holder's untenable FTR positions. FTRs expose their holders to the risk of almost unlimited losses regardless of whether the path cleared the auction as a prevailing or *counterflow* FTR.[26] This risk further increases as the term of the FTR lengthens because of the probability that congestion patterns will change. The risk of default, however, is minimized when an FTR is used as part of a strategy to hedge congestion costs by pairing the FTR with an energy transaction settled in the Day-Ahead Energy Market.

The ISO is working with NEPOOL participants through an FTR credit working group, organized under the NEPOOL Budget and Finance Committee, to develop changes necessary to minimize exposure to payment defaults resulting from FTR market participation. The discussions will focus on improving the financial-assurance policy to better manage the ISO's FTR risk exposure and may include market design revisions.

The FTR market performed competitively during 2007 on the basis of the arbitrage performance metric of path profitability. However, at the end of 2007, FTRs were not fully funded, which limited the effectiveness of the FTR hedge. The ISO has taken two actions that should lessen any shortfalls in the future. First, the ISO has proposed changes to Operating Procedure 3 (OP 3), *Transmission Outage Scheduling*, to enhance the coordination between FTR scheduling and outage coordination.[27] Second, the ISO has begun developing advanced applications for interface-limit calculations that will promote more consistent application of interface limits across FTRs and the Day-Ahead and Real-Time Energy Markets and will thus improve the effectiveness of the FTR hedge.

1.3.7 Demand Resources

Participants' modification of electric energy consumption through demand response and other types of demand resources may provide relief from capacity and reserve constraints in the wholesale electricity markets, or they may promote more economically efficient uses of electrical energy. Along with adequate supply and a robust transmission infrastructure, demand resources are important aspects of a well-functioning wholesale market that improve market efficiency. The ISO operates three types of demand-response programs: those activated by price, those activated for reliability, and those that reduce on-peak consumption.

The price-response programs are made up of a Day-Ahead Load-Response Program (DALRP) and the Real-Time Price-Response Program. Three reliability programs, which are activated as needed during a capacity deficiency, include a 30-minute notice program, a two-hour notice program, and a two-hour notice profiled-response program. The measured on-peak reduction demand-response programs were introduced as part of the FCM and are intended to reduce planning capacity needs. These FCM program resources, termed *other demand resources* (ODRs), credit energy efficiency,

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[25] 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.

[26] With a counterflow FTR, the participant acquires power-flow capacity against the prevailing direction of power flows, represented by other participants' offers in the auction (see Section 7.1).

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

load management, and distributed generation with capacity on the basis of their on-peak contributions.[28] The past three years have seen a large increase in demand response and ODRs, as shown in Figure 1-8.

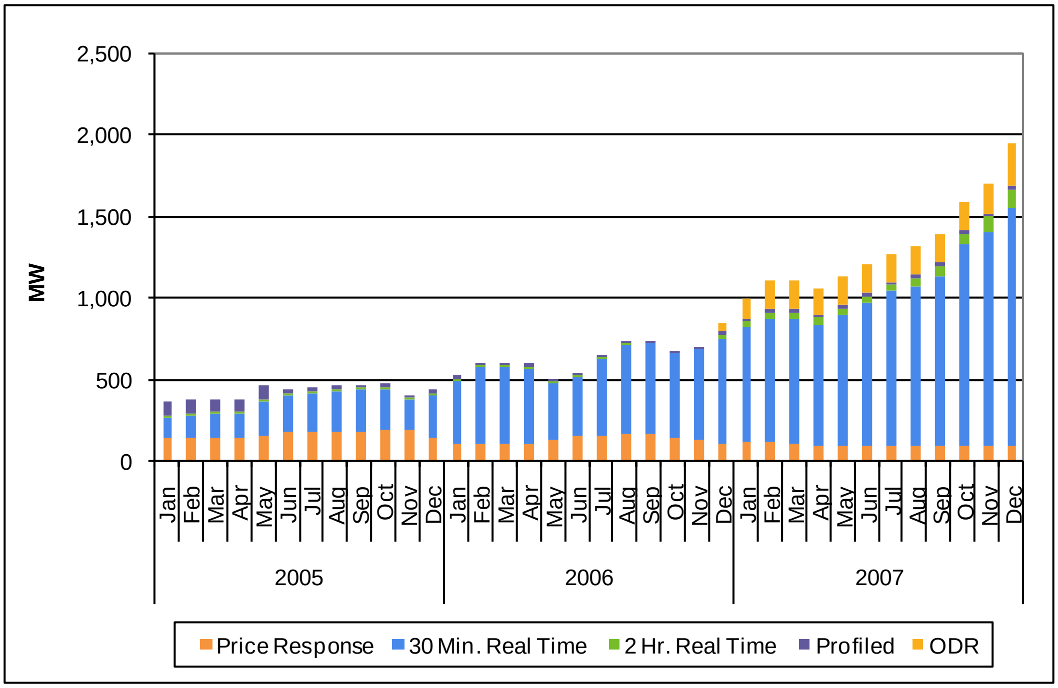

Figure 1-8: **Monthly megawatts enrolled in ISO demand-resource programs, 2005 to 2007.**

Overall enrollment in demand-response programs increased approximately 162% during 2007, from an annual monthly average of 646 MW in 2006 to 1,693 MW in 2007. The total increase between January 2005 and December 2007 has been 360%. Most of these increases have been in the Real-Time 30-Minute Demand-Response Program. The very sizable increase in these programs is most likely a result of the implementation of the Forward Capacity Market and its capacity transition payments. This assessment is supported by the fact that all the increases in demand-resource participation have been in the reliability programs and in the ODR categories, both of which are eligible for FCM transition payments. Audits of the 30-minute and two-hour demand-response programs on August 15, 2007, and of the real-time price-response and profiled demand-response programs on August 17, 2007, showed that participants reduced energy usage from the bulk power system by 2,143 MWh.[29] This was 77% of the enrolled amount, which is similar to historical response rates from audits and actual event activations. The now-implemented FCM rules have revised the incentive structure for demand-response participants. The rule revisions are expected to improve the estimates for load-interruption capability and the performance of demand-response resources.

[28] Distributed generation is a resource that is located behind the end-use customer's billing meter, which reduces the amount of electric energy and capacity that would have been drawn from the electricity network. The nameplate capacity for distributed generation must not exceed 5 MW or the most recent annual customer peak demand, whichever is greater.

[29] 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, 2007. The rule requires the audits (when necessary) to occur between August 15 and August 31.

The ISO identified a design flaw in the DALRP that resulted in inappropriate customer baseline calculations, and it filed market-rule revisions in February 2008. More details are included in Section 8.4.1.

The Real-Time Price-Response Program was called on 229 days, an unexpectedly high frequency. This program is designed to trigger interruptions when the real-time price is expected to be above \$100/MWh. In 79% of the interruptions, the actual real-time price fell below the \$100/MWh trigger. The ISO will review the Real-Time Price-Response Program in 2008. As the region gains experience with expanded demand resources, changes and improvements can be expected. These should be viewed as part of the necessary learning process that comes with the type of growth New England has achieved in the availability of demand resources.

1.4 Conclusions and Recommendations

The ISO-operated markets provide participants and policymakers transparent wholesale market price signals that guide long-term investment in generation and transmission infrastructure. To support this, continued market development is required to complete the Forward Capacity Market design and FCM-conforming changes to energy and ancillary services markets and to integrate demand resources into market operations.

This Annual Markets Report has assessed the market results for 2007. The energy prices have closely tracked fuel costs and changes in demand, evidence of a competitive market. More detailed analyses support the conclusion that the wholesale electricity markets in New England continued to perform competitively during 2007. Market power monitoring and mitigation continue to be needed, particularly in constrained areas. While the market structure is complete, possibilities still exist for efficiency improvement through incremental changes in market elements.

The report draws a number of conclusions and makes a number of recommendations for evaluating and making incremental improvements to the market design rules or specific market design parameters. These are grouped into four areas: reserve market parameters, FTR market issues, demand-response program improvements, and the thresholds used in Net Commitment-Period Compensation (NCPC) mitigation.

- Reserve Markets—The parameters used to calculate the quantity of reserves purchased for the Rest-of-System reserve zone in the Forward Reserve Market, the mechanism for calculating the FRM threshold price, and the level of reserve-constraint penalty factors used in real-time reserve pricing should be evaluated.
- FTR Markets—In the FTR markets, participant defaults in PJM have refocused the ISO's ongoing efforts to evaluate the financial-assurance rules. The ISO also is evaluating possible improvements to the procedures for scheduling outages and the methods used to calculate interface limits used in FTR auctions and the Day-Ahead and Real-Time Energy Markets. These efforts will promote the consistency of transfer limits and improve the effectiveness of FTRs as a hedge of day-ahead congestion costs.
- Demand Resources—The ISO identified a market design flaw in the customer baselines used in the Day-Ahead Load-Response Program. The ISO has filed revisions to the market rule to fix the design flaw. The Real-Time Price-Response Program was called more often than expected, and in 79% of those interruptions, prices were lower than the intended \$100/MWh activation price. The ISO also is evaluating possible changes to the Real-Time Price-Response Program.

- Daily Reliability Payments—NCPC is intended to ensure that resources will not incur losses by following out-of-merit scheduling instructions. Analysis confirms that a few resource owners have earned NCPC payments above the amount required to prevent losses. The ISO is recommending an evaluation of the NCPC mitigation thresholds.

Table 1-2 provides a summary of selected market results detailed in the individual sections of this report.

Table 1-2
2007 Results Summary

Section	Topic	Data Summary
Section 2—Electric Energy Markets		
2.2	**Peak demand and electric energy consumption**	Annual actual electric energy consumption increased from 132,078,000 MWh in 2006 to 134,525,000 MWh in 2007, or 1.9%. Weather-normalized electric energy consumption increased by a smaller percentage (0.9%). The actual peak demand in 2007 of 26,134 MW was 7% lower than the historical high of 28,130 MW set during the summer of 2006. The weather-normalized system peak increased by 1.9%. The continued growth of weather-normalized peaks at a rate greater than weather-normalized total consumption results in a continued decline in the weather-normalized load factor. In contrast to the weather-normalized load factor, the actual load factor for 2007 increased as a result of the higher actual energy consumption and lower actual peak demand.
2.3.1	**System capacity growth**	Total system capacity grew slightly during 2007. Summer system capacity in 2007 was 32,918 MW compared with 31,193 MW in 2006. Of the 1,725 MW of increased system capacity, the majority (1,681 MW) was from higher capacity net of firm purchases and sales, and 44 MW was summer claimed capability.
2.3.5	**Imports and exports**	New England remained a net importer of power during 2007. The volume of systemwide net imports has remained relatively constant year to year. New England was a net importer from Canada and a net exporter to New York. The volumes imported from Canada and exported to New York have increased. During 2007, net imports from other control areas served about 4.5% of NEL.
2.4	**Wholesale electricity price levels and fuel costs**	The average real-time electricity price at the Hub in 2007, weighted by system load, was $69.57/MWh, an increase of 11% from an average of $62.74/MWh in 2006. The increase in prices is attributable to higher fuel prices and higher average demand for electricity. The fuel-adjusted electric energy price was $45.15/MWh, a 5.8% increase from the 2006 level. The average fuel-adjusted price for 2000 to 2006 was $45.01/MWh.
2.4.3	**Day-ahead and real-time prices**	During 2007, the yearly average day-ahead price was 1.8% higher than the average real-time price. In 2006, the difference was 2.0%. Each load zone except Connecticut also demonstrated modest price premiums in the Day-Ahead Energy Market over the Real-Time Energy Market. In Connecticut, average real-time prices were 4 cents higher than average day-ahead prices.

Section	Topic	Data Summary
2.4.6	**Zonal price separation**	Price separation among load zones was less pronounced in 2007 than in 2006, although Connecticut LMPs continued to be higher than those in other zones. LMPs were lowest in Maine. Overall for the year, the average difference between the LMPs for Connecticut and Maine was $7.35/MWh in the Day-Ahead Energy Market and $8.10/MWh in the Real-Time Energy Market. Day-ahead and real-time LMPs in the NEMA/Boston zone were lower than in most other load zones in 2007; the exceptions were Maine and Rhode Island.
2.5	**Critical power system events**	Higher-than-expected demand for electricity that was sometimes combined with supply disturbances required the ISO to declare OP 4 actions during 2007. Systemwide, OP 4 was declared on February 10, August 2, and September 8. On December 1, OP 4 was declared first for Maine and then systemwide because of a disturbance in the natural gas supply infrastructure. Some OP 4 actions continued in Maine on December 2, 2007. Throughout each of these events, the ISO maintained system reliability, and no forced load reductions were needed.
Section 3—Forward Capacity Market		
3.2	**Capacity requirement**	The auction met the Installed Capacity Requirement (ICR) of 32,305 MW for the 2010/2011 capability year by selecting approximately 1,813 MW of new supply and demand resources along with 30,492 MW of capacity from existing resources. Of the new resources chosen, 1,188 MW represent new demand-resource projects, and 626 MW represent new supply projects. The auction closed at the administrative floor price of $4.50/kW-month, with 2,047 MW of surplus capacity.
3.5	**Transition payments**	FCM transition payments replaced the Installed Capacity Market in December 2006 and will continue until the 2010/2011 capability year when the FCM payments based on the auction results will begin. During 2007, FCM transition payments to qualifying capacity resources totaled $1.3 billion.
3.7	**First Forward Capacity Auction**	The Forward Capacity Auction was completed in February 2008. A total of 32,392 MW of existing capacity qualified for the auction along with 6,937 MW of new capacity projects. Almost 36% of the qualified new capacity projects was from demand-resource projects.
Section 4—Reserve Markets		
4.2.1	**Forward Reserve Market auctions**	Two forward-reserve auctions for locational forward-reserve products were conducted in 2007: in April 2007, for summer 2007; and in August 2007, for the winter 2007/2008 period.[a] For the summer 2007 auction, 10-minute nonsynchronized reserves (TMNSR) cleared at $10,800/MW-month, while the price for 30-minute operating reserves (TMOR) was $3,550/MW-month in the Rest-of-System reserve zone. In the winter 2007/2008 auction, TMNSR cleared at $9,050/MW-month, while no TMOR cleared in the ROS reserve zone. Offered quantities were short of requirements in the SWCT and CT reserve zones in both auctions. Consequently, the clearing prices in these areas were set to the offer cap of $14,000/MW-month. In the summer 2007 auction, offered quantities in the NEMA reserve zone were short of requirements, which caused the clearing price to be set to $14,000/MW-month. The requirements in NEMA were met in the winter 2007/2008 auction, which resulted in a clearing price there of $8,500/MW-month for TMOR and $14,000/MW-month for TMNSR.

Section	Topic	Data Summary
4.3	**Real-time reserve pricing**	Positive reserve-clearing prices occurred in at least one reserve zone in 452 hours during 2007. Positive reserve-clearing prices occurred most frequently in the SWCT reserve zone, where prices for local 10-minute spinning reserves (TMSR) were positive in 5.1% of the hours. In the Rest-of-System reserve zone, TMSR prices were positive in 3.3% of the hours.
4.6	**Forward Reserve Market operations**	Net forward-reserve credits were about $163.8 million in 2007. Failure-to-reserve and failure-to-activate penalties for the year totaled $6.4 million.
		Section 5—Regulation Market
5	**Regulation Market**	Total Regulation Market costs fell from $78.1 million in 2006 to $43.8 million in 2007. The markets continued to provide sufficient amounts of regulation, and the New England Control Area fully complied with NERC reliability requirements for regulation.
		Section 6—Reliability Costs and Peaking-Unit Safe-Harbor Bidding
6.1	**Daily reliability commitments and payments**	The cost of payments to maintain daily reliability increased 6% from $232 million in 2006 to $247 million in 2007. The increase is the result of higher fuel prices and higher voltage payments to resources in the NEMA load zone. Second-contingency payments, the largest category, decreased 6% systemwide.
6.2	**Reliability Agreements**	Capacity under Reliability Agreements decreased dramatically between 2006 and 2007, dropping from 5,843 MW in 2006, or 19% of total system capacity, to 3,203 MW in 2007, 10% of systemwide capacity. At the end of 2007, no generating resource in NEMA had a Reliability Agreement, a decrease from 62% of NEMA capacity having agreements at the end of 2006.
		Section 7—Financial Transmission Rights
7	**Financial Transmission Rights**	FTRs were offered to the marketplace in 12 ISO-administered monthly auctions and one annual auction for 2007. Participation in the auctions was strong, and market participants purchased FTRs that generally were consistent with expected patterns of congestion. Net auction revenues from the annual and 12 monthly auctions totaled about $122 million.
		Section 8—Demand Resources
8	**Demand resources**	In 2006, with the advent of the Forward Capacity Market transition payments, the ISO introduced a category of demand resources called *other demand resources*, which qualify as capacity resources. ODRs consistently reduce on-peak demand. With FCM transition payments as incentives for increased enrollment, the level of participation by demand resources increased approximately 162% in 2007, from an annual monthly average of 646 MW in 2006 to 1,693 MW in 2007.
8.4	**Demand-response interruptions**	The ISO identified flaws in the Day-Ahead Load-Response Program and has filed revisions to resolve the problems. Other refinements in existing programs may be desirable.

Section	Topic	Data Summary
Section 9—Oversight and Analysis		
9.2	**Market power mitigation**	During 2007, the ISO exercised its market-mitigation authority 16 times as part of its responsibility to monitor the market and ensure efficient and competitive market results. Thirteen mitigation events were for economic withholding in the Real-Time Energy Market, and the remaining three mitigation events were for economic withholding as part of the evaluation of Net Commitment-Period Compensation (see Section 9.3). Mitigation was imposed when the participants did not adequately explain a supply offer that exceeded conduct and market-impact thresholds. As a result of the mitigation, a supply offer intended to represent the unit's marginal costs was substituted for the generating resource's offer.

(a) Ten-minute nonsynchronized 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 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.

Section 2
The Electric Energy Markets

The electricity markets operated by the ISO include a Day-Ahead Energy Market and a Real-Time Energy Market, each producing a separate but related financial settlement. This arrangement is known as a *multi-settlement system*. 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 capacity into the market, real-time hourly self-schedules (i.e., operating at a determined output level regardless of price), self-curtailments, transmission or generation outages, and unexpected real-time system conditions. The Real-Time Energy Market balances differences between the day-ahead scheduled amounts of electricity and the actual real-time load requirements. Participants either pay or are paid the real-time locational marginal price for the amount of load or generation in megawatt-hours that deviates from their day-ahead committed schedules. Locational marginal pricing is a way to efficiently capture the impacts on electric energy prices caused by locational variations in supply, demand, and transmission limitations at every location on the system.

This section contains information about the Day-Ahead and Real-Time Energy Markets. Information on the factors that drive the price of electric energy, market results for 2007, and an analysis of the data are included for each market.

2.1 Underlying Drivers of Electric Energy Market Prices

The ISO calculates and publishes day-ahead and real-time LMPs at five types of locations, called *pricing locations*. These include the external interface proxy nodes, load nodes, individual generator-unit nodes, load zones, and a trading hub (Hub). New England is divided into the following load zones: Maine, New Hampshire, Vermont, Rhode Island, Connecticut, Western/Central Massachusetts (WCMA), Northeast Massachusetts and Boston (NEMA), and Southeast Massachusetts (SEMA). The Hub, which contains a specific set of predefined nodes, is used to establish a reference price for electric energy trading and hedging. The Hub also is a location used in the FTR markets (see Section 7).

The market-clearing process calculates and publishes LMPs at these locations based on supply offers, virtual bids, and day-ahead demand bids in the Day-Ahead Energy Market and on supply offers and real-time load in the Real-Time Energy Market. A generator is paid the price at its node, whereas participants serving demand pay the price at the load zone. This is a load-weighted average price of the zone's load-node prices. (Refer to Section 2.1.2 for more information about how the market price is determined.)

LMPs differ among locations as a result of the marginal costs of congestion and losses. *Congestion* is caused by transmission constraints that limit the flow of otherwise economic power. Congestion costs arise because of the need to dispatch individual generators to provide more or less energy to respect transmission constraints. The marginal cost of losses is a result of physical losses that arise as electricity travels through the transmission lines. Physical losses are caused by resistance in the transmission system and are inherent in the existing transmission infrastructure. As with the marginal cost of congestion, the marginal cost of losses has an impact on the dispatch level of generators 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 (in megawatts) of load. This incremental megawatt of load would be served by the generator with the lowest cost, and energy from that generator would be able to flow to any node over the transmission system.

The key factors that influence the LMPs are supply and demand. Supply is influenced in turn by fuel prices and the frequency and location of transmission constraints. The following subsections elaborate on each of these factors.

2.1.1 Supply and Demand

In the Day-Ahead Energy Market, 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. They also may offer virtual supply and bid virtual demand (see Section 2.2) at the Hub, load zones, the external interface pricing nodes, or individual generator or load nodes. Appendix A.1 provides a monthly breakdown of energy market volumes by numerous categories. Generating units offer their output at the pricing node specific to their location. 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. The processing of the Day-Ahead Energy Market results in binding financial schedules and commitment orders to generators. In the Day-Ahead Energy Market, participants have incentives to submit supply offers that reflect their units' marginal costs of production, which are largely driven by fuel costs. Supply offers also incorporate the units' operating characteristics. Separate start-up and no-load offers are submitted as well. Demand bids reflect participants' load-serving requirements and accompanying uncertainty, tolerance for risk, and expectations about congestion.

After the Day-Ahead Energy Market clears, the supply at each location can be affected in two ways. First, generators that were not committed in the Day-Ahead Energy Market can request to self-schedule their units for real-time operation. Alternatively, units that were committed can incur a forced outage or request to be decommitted. Second, as part of its Reserve Adequacy Analyses (RAA) (see Section 6.1), the ISO may be required to commit additional generating resources to support local-area reliability or to provide contingency coverage.[30] Finally, all generators have the flexibility to change their incremental energy-supply offers during the reoffer period.[31]

In the Real-Time Energy Market, the ISO dispatches generators to meet the actual demand on the system and to maintain the required operating-reserve capacity. Higher or lower demand than that scheduled day ahead, actual generator availability, and system operating conditions all can affect the level of generator dispatch and therefore the real-time LMPs. In the Real-Time Energy Market, the ISO balances supply and demand, while ensuring that reserves are sufficient and transmission line loadings are safe. Unexpected increases in demand, generating-unit outages, and transmission line outages all can cause the ISO to call on additional generating resources to preserve the balance between supply and demand.

[30] 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.

[31] The reoffer period is normally 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 supply offers or revised demand bids associated with dispatchable asset-related demand.

2.1.2 Fuel Prices

Fuel prices alone account for a large portion of year-to-year electricity prices. For most electricity generators, the cost of fuel is the largest production cost variable, and as fuel costs increase, the prices at which generators submit offers in the marketplace increase correspondingly.

Over the past five years in New England, new generating capacity has been almost entirely fired by natural gas. Generating units burning natural gas or fuel oil, or capable of burning both natural gas and oil, constitute approximately 62% of electric generating capacity in the region. During most hours, a generator burning one of these two fuels is a marginal unit, which results in New England electricity prices being highly sensitive to changes in the price of fuel oil and natural gas. On average, both oil and gas prices increased in 2007. The average annual price of fuel oil increased 17% from 2006, while the average annual price of natural gas increased 9%. In particular, No. 6 fuel oil has become more expensive than natural gas, which changes the dispatch order of some generation resources.

2.1.3 Transmission Constraints

In the Day-Ahead Energy Market, RAA, and Real-Time Energy Market, generating units are committed to ensure that the levels of cleared, anticipated, and actual demand can be served reliably. The commitment takes into account transmission system limits, the need for reserves, and the need to provide contingency coverage. High demand relative to economic supply in a given area may result in binding transmission constraints, which then would require the selection of more expensive generation and would lead to higher LMPs in that area. In contrast, export-constrained areas will experience lower LMPs relative to unconstrained areas.

2.2 Electric Energy Demand in 2007

Average loads and system peak demand in 2007 both were consistent with long-term trends. Temperatures also were consistent with long-term trends, and there were no periods of unusually high temperatures combined with high humidity, which drive peak loads. This is in contrast to 2006 when the average load levels in New England were lower than expected, but there were a few unusually high load days that were driven by high temperatures combined with high humidity. The net energy for load (NEL) supplied to the system in 2007 was 134,525,000 MWh, an increase of 1.9% from the 2006 level.[32] Historically, increases and decreases in demand have correlated with changes in economic activity, electricity prices, weather conditions, and consumer preferences (e.g., an increased use of centralized air conditioning and greater use of home electronics). Employment grew by 1% and real income by 3.2% in 2007. Changes in retail electricity prices and weather were modest.

Figure 2-1 shows annual NEL for 1980 through 2007. After a decrease in NEL from 2005 to 2006, aggregate energy consumption increased in 2007. This increase followed historical patterns resulting from weather, economic and real income growth, and a smaller increase in retail electricity prices (3.4% from 2006 to 2007, compared with a 21% rise from 2005 to 2006).

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

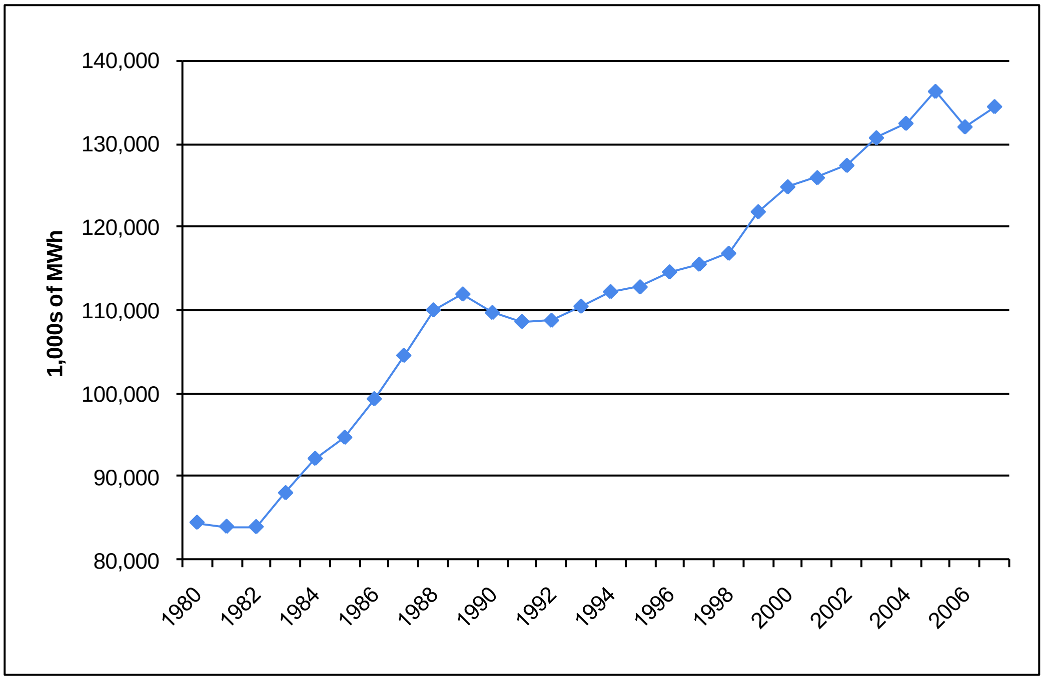

Figure 2-1: New England actual net energy for load, 1980 to 2007.

Since NEL is influenced significantly by weather, the ISO also calculates weather-normalized NEL (i.e., the NEL that would have been observed if weather were normal). This calculation indicates that after weather normalization, annual consumption rose 0.9% from 2006 to 2007.[33] Table 2-1 shows the annual and peak electric energy statistics for 2006 and 2007.

Table 2-1
Annual and Peak Electric Energy Statistics, 2006 and 2007

	2006	2007	Change	% Change
Annual NEL (MWh)	132,078,000	134,525,000	2,447,000	1.9
Normalized NEL (MWh)	132,480,000	133,720,000	1,240,000	0.9
Recorded peak demand (MW)	28,130	26,143	–1,987	–7.1
Normalized peak demand (MW)	26,940	27,460	520	1.9

As illustrated in Figure 2-2, New England monthly temperatures in 2007 were consistent with long-term averages. February was slightly colder than normal, while September and October were slightly warmer than normal.[34]

[33] The ISO uses statistically derived factors to adjust energy consumption levels to reflect the deviation of actual weather from 20-year average or "normal" levels. In the weather-normalization calculation, consumption is adjusted downward when temperatures are more severe than normal and upward when temperatures are milder than normal. Data for summer months also account for the effect of humidity on consumption levels.

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

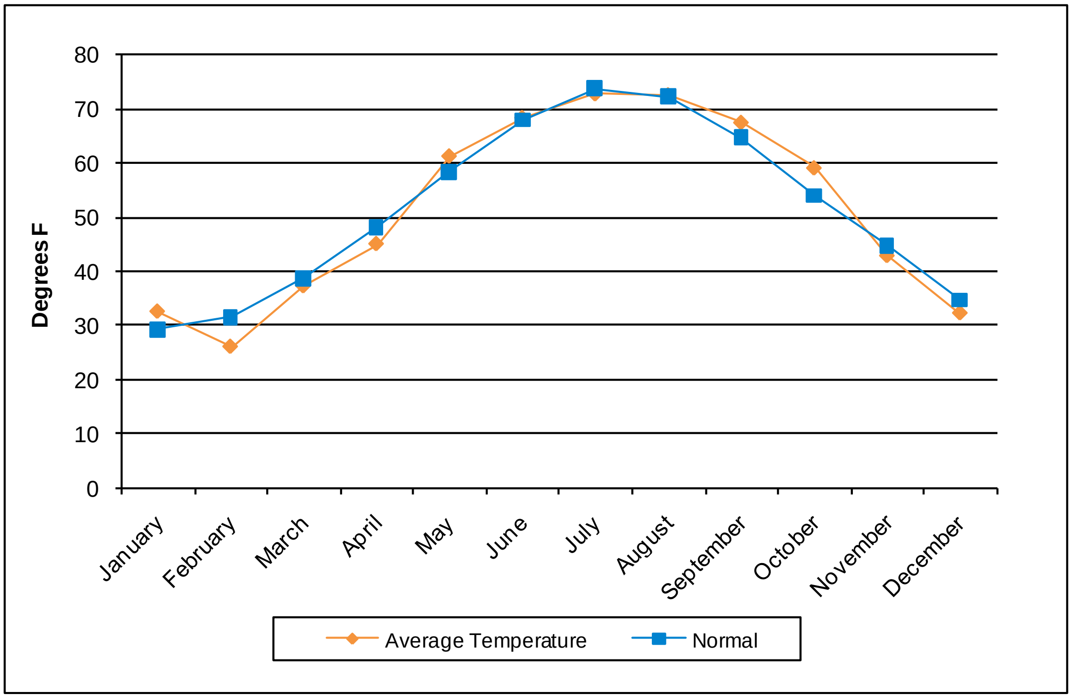

Figure 2-2: Average temperatures for 2007 compared with normal values.

Loads exceeded 25,000 MW in only 17 hours in 2007. The 2007 system-peak hourly demand of 26,143 MW occurred on August 3. The temperature at the time of this peak was 91°F. By comparison, demand exceeded 25,000 MW in 55 hours in 2006 and 28 hours in 2005. The ISO calculates a weather-normalized peak demand for the summer and winter seasons. After weather normalization, the 2007 summer seasonal peak increased 1.9% over the 2006 weather-normalized peak.

Figure 2-3 and Figure 2-4 show the actual system electrical load for New England over the past five years as load-duration curves, ordering load levels from highest to lowest. The duration curve for each year shows the percentage of time the hourly load was at or above the load levels shown on the vertical axis. Figure 2-4, which includes only the highest 5% of hours, shows that 2007 had much lower peak loads than 2005 and 2006.

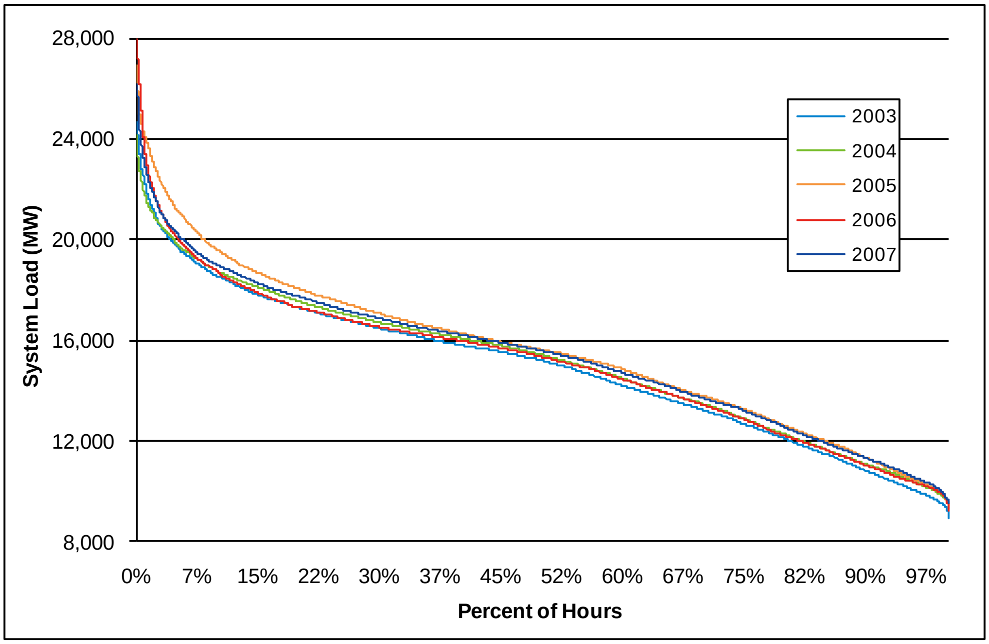

Figure 2-3: New England hourly load-duration curves, 2003 to 2007.

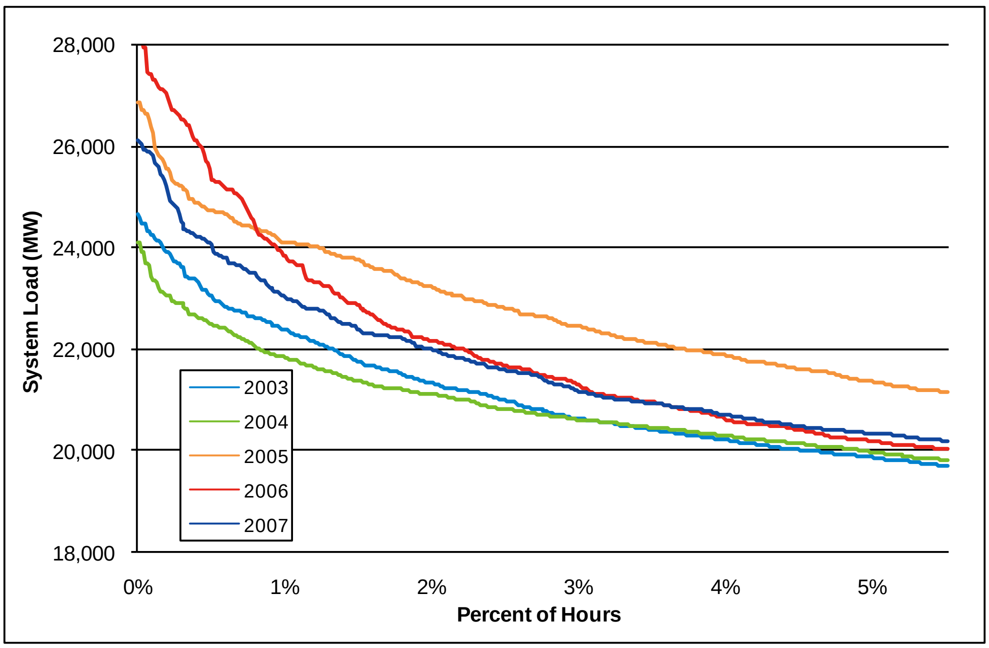

Figure 2-4: New England hourly load-duration curves, top 5% of hours, 2003 to 2007.

2.2.1 2007 Load Factor

Figure 2-5 shows historical load factors for New England expressed as a percentage for both weather-normalized and actual load levels. New England is a summer-peaking region in which hot weather and the resultant use of air conditioners drives peak consumption. Because summer peak demand has grown disproportionately compared with average demand, load factors have been declining. Over the past few decades, weather-normalized load factors (i.e., the ratio of the average hourly demand during a year to the peak hourly demand, both adjusted to normal weather conditions) have fallen significantly, dropping from 65% in 1980 to 56% in 2007. In addition to air-conditioning saturation, conversion from individual room air conditioning to central air conditioning and an increase in the size of the homes being cooled have been primary factors contributing to the long-run decline in the summer-peak load factor. From 2006 to 2007, actual demand increased, while the summer peak decreased, resulting in an increase in the actual load factor. However, weather- normalized peak hourly demand rose faster than average demand, resulting in a lower weather-normalized load factor. Because peak electricity consumption is projected to grow faster than average consumption, load factors likely will continue to decline in the future.

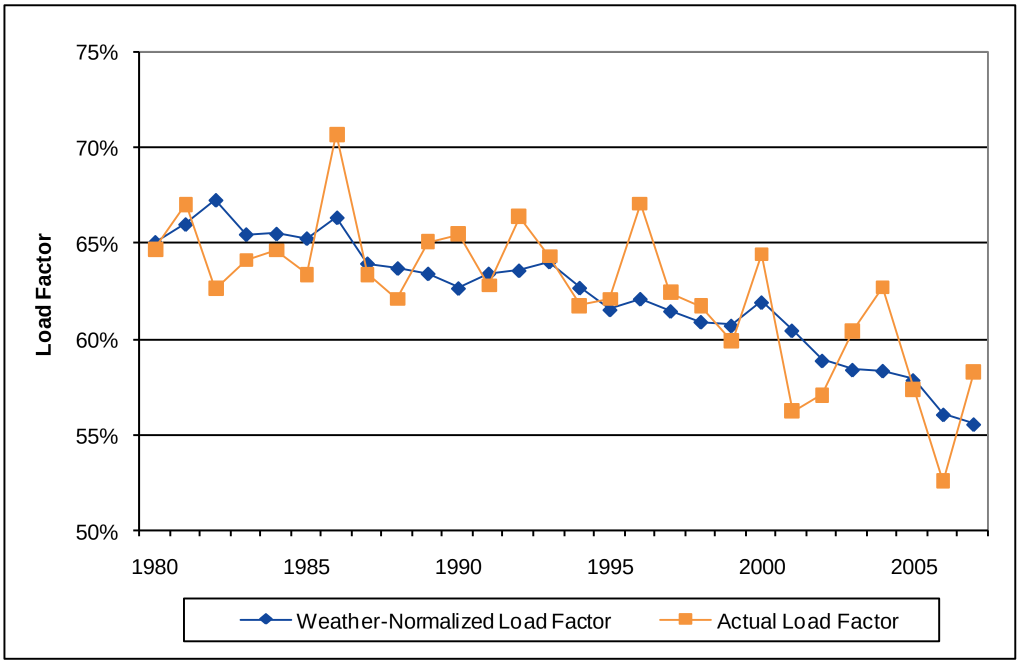

Figure 2-5: New England summer-peak load factors, 1980 to 2007.

The higher electricity consumption in the summer leads to higher wholesale electricity prices and increasing amounts of investment in generation and transmission to meet the peak demand for only a small number of hours per year. Additional demand-response and other demand resources would decrease peak loads, which would result in higher load factors.[35]

2.2.2 Day-Ahead Demand and Virtual Trading Trends

Two types of demand bids can be submitted in the Day-Ahead Energy Market: demand bids at the zonal level, and decremental bids that can be submitted at any pricing node on the system. Decremental bids are referred to as *virtual demand*. Demand bids may be submitted only by entities that have real-time load obligations (RTLOs) (i.e., they are serving load). Demand bids can be fixed or price sensitive and are made only at the zonal level. Virtual demand can be price sensitive only and submitted by any participant that satisfies the financial-assurance requirements detailed in the market rules.

[35] *Demand response* in wholesale electricity markets occurs when market participants modify their consumption of electric energy, such as shifting their consumption to off-peak periods. The ISO operates several demand-response programs, as discussed in Section 8. The Forward Capacity Market added two new programs, allowing energy efficiency and distributed generation to compete in the capacity market as suppliers.

Both types of bids 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 the price of RTLOs. Virtual demand bids can be used to arbitrage 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.

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 Energy Markets.

Virtual supply offers that clear in the Day-Ahead Energy Market create a financial obligation for the participant to purchase electric energy at the same location during the Real-Time Energy Market. Cleared virtual demand bids create a financial obligation for the participant to sell at the same location in the Real-Time Energy Market. That is, a virtual supply offer in the Day-Ahead Energy Market is "filled" by a purchase in the Real-Time Energy Market, and a virtual demand bid in the Day-Ahead Energy Market is sold in the Real-Time Energy Market. 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 cost. Figure 2-6 shows average hourly quantities of fixed and price-sensitive day-ahead demand and virtual demand and supply for 2007.

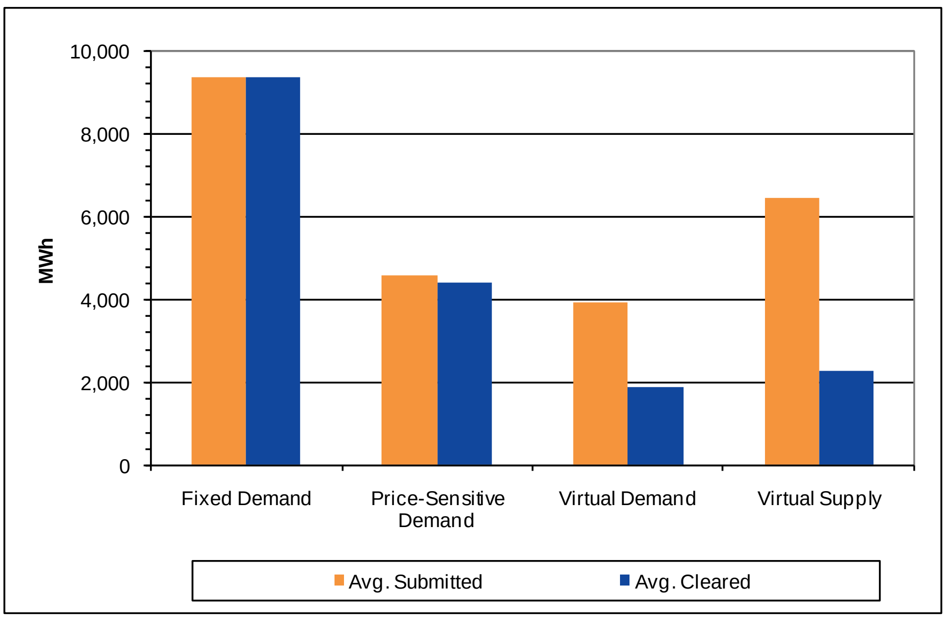

Figure 2-6: Average hourly submitted and cleared demand, virtual demand, and virtual supply, Day-Ahead Energy Market, 2007.

During 2007, 60% of cleared demand bids were fixed bids, insensitive to price, while 28% of the bids were price sensitive. The remaining 12% of cleared day-ahead demand was composed of cleared virtual demand bids representing day-ahead locational purchases of electric energy. Figure 2-7 shows the total monthly submitted and cleared virtual demand from January 2006 through December 2007. The figure shows that the volumes of both submitted and cleared virtual demand increased in 2007 compared with 2006.

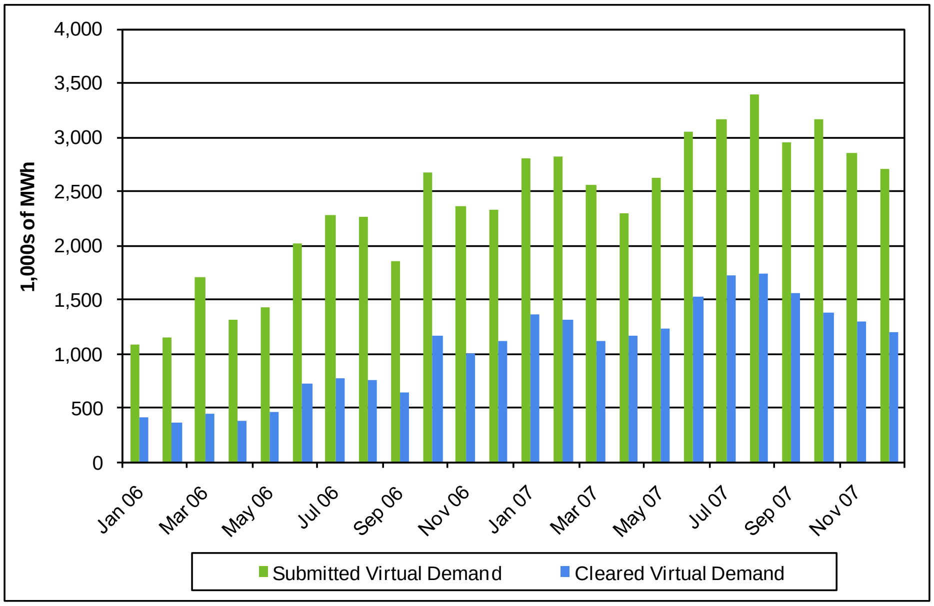

Figure 2-7: Monthly total submitted and cleared virtual demand, January 2006 to December 2007.

Figure 2-8 shows the monthly submitted and cleared virtual supply from January 2006 through December 2007. Similar to the trend in virtual demand, the volume of submitted and cleared virtual supply offers increased. Much of the increase in virtual electric energy (MWh) offered to the day-ahead market, however, was the result of a few participants that increased their virtual trading activity by large percentages to arbitrage the price. This increase in virtual transaction offers indicates a more mature market.

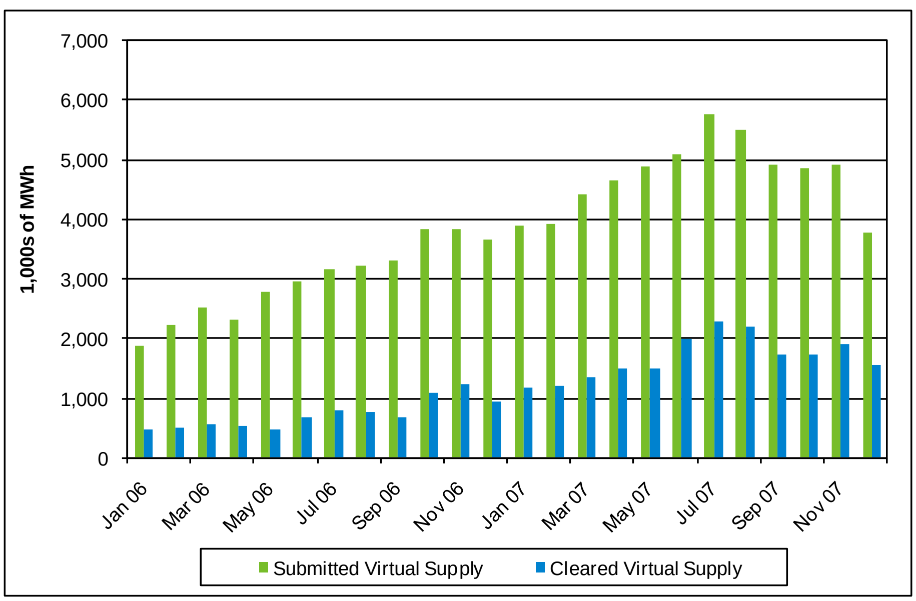

Figure 2-8: Monthly total submitted and cleared virtual supply, January 2006 to December 2007.

2.3 Electric Energy Supply in 2007

This section discusses elements of electric energy supply in 2007, including generation capacity, fuel types, self-scheduling, imports and exports, reserve margins, virtual supply, and changes related to the reoffer period.

2.3.1 System Capacity

The total 2007 summer seasonal claimed capability (SCC-S) grew by 44 MW, from 30,835 MW in 2006 to 30,879 MW in 2007.[36] Total summer peak capability, including firm capacity imports and exports (referred to as capacity net of purchase and sales), grew from 31,193 MW in 2006 to 32,918 MW in 2007. These values represent actual conditions as of the summer peaks. The 2007 SCC-S value does not include the 75 MW Pierce generating station that was put in commercial service in the fourth quarter of 2007. By comparison, no new generation resources were added to the system in 2006, while 92 MW of new generation were added in 2005; 656 MW were added in 2004; 2,949 MW were added in 2003; and 2,786 MW were added in 2002.[37]

New England has adequate installed capacity to meet its regional capacity needs through 2009.[38] The ISO is optimistic that adequate demand and supply resources will be purchased and installed in time to meet the projected capacity needs and the resource adequacy requirements for 2010 and beyond. As part of the system planning process, the ISO maintains a Generator Interconnection Queue, which tracks the resources that have requested interconnection studies.[39] As of January 4, 2008, about one month before the first Forward Capacity Auction, 97 projects totaling 13,066 MW, an increase of 24% from January 2006, were listed in the queue.[40] (See Section 3 for more information on the FCA.)

Figure 2-9 shows summer capacity (MW) by year and by fuel type for the past five years. Capacity levels have changed little during this period.[41] In 2007, dual-fueled generators capable of burning either oil or natural gas made up 24% of installed capacity, while natural-gas-fired generators made up 26% 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.

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[36] *Claimed capability* is a measure of capacity. *System capacity* includes capability available to New England adjusted for transfers of capacity between control areas through net purchase and sales. See the ISO's *2008–2016 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT)* (2007).

[37] No new generating infrastructure was added to the system in 2006; however, some resources came from "behind the meter," resulting in additional SCC-S.

[38] See the ISO's *2007 Regional System Plan* (RSP07). (October 18, 2007). Available online at http://www.iso-ne.com/trans/rsp/2007/rsp07_final_101907_public_version.pdf or by contacting ISO Customer Service at 413-540-4220.

[39] Additional information on the projects in the Generation Interconnection Queue is available online at the "New or Modified Interconnections" section of the ISO Web site, http://www.iso-ne.com/genrtion_resrcs/nwgen_inter/index.html.

[40] Presentation by the ISO's chief operating officer at the NEPOOL Participants Committee meeting. (January 4, 2008). Available online at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2008/jan42008/npc_jan2008.pdf.

[41] 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.

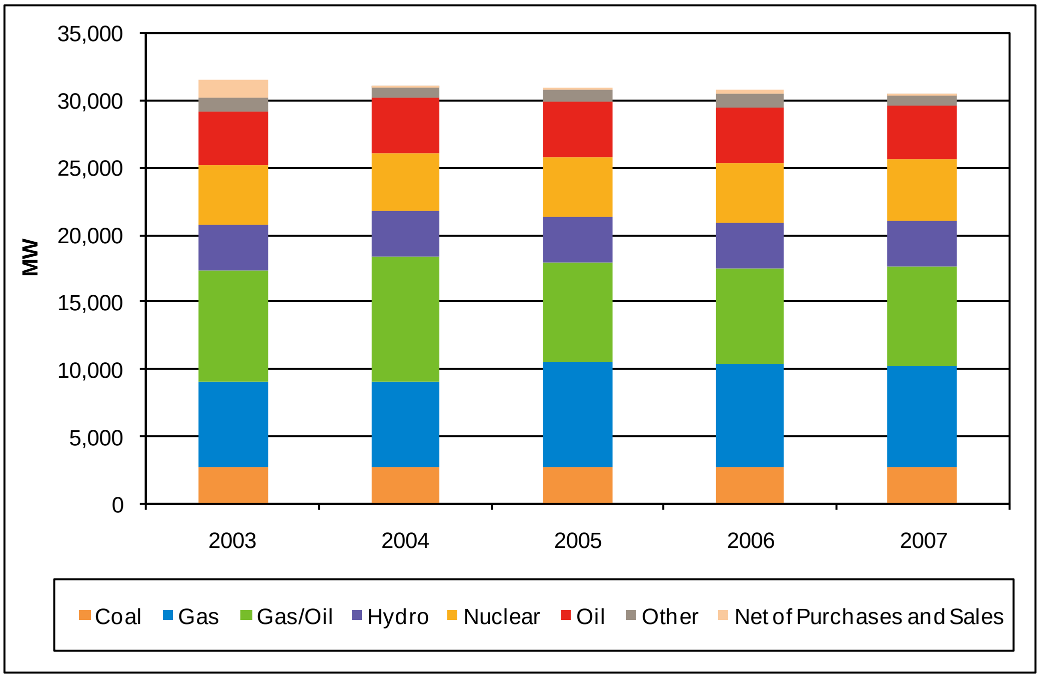

Figure 2-9: System summer capacity by generator type.

Note: Capacity values are for August, summarized from the ISO's forecast reports on capacity, energy, loads, and transmission (CELT Reports), which are available online at http://www.iso-ne.com/trans/celt/report/index.html.

Figure 2-10 compares zonal demand and generation for generators within each load zone. Generators within the Rhode Island, New Hampshire, and SEMA load zones produced more power than was used within these zones, while the Vermont, Maine, NEMA, WCMA, and Connecticut load zones all had demand that was greater than the power generated within these zones.

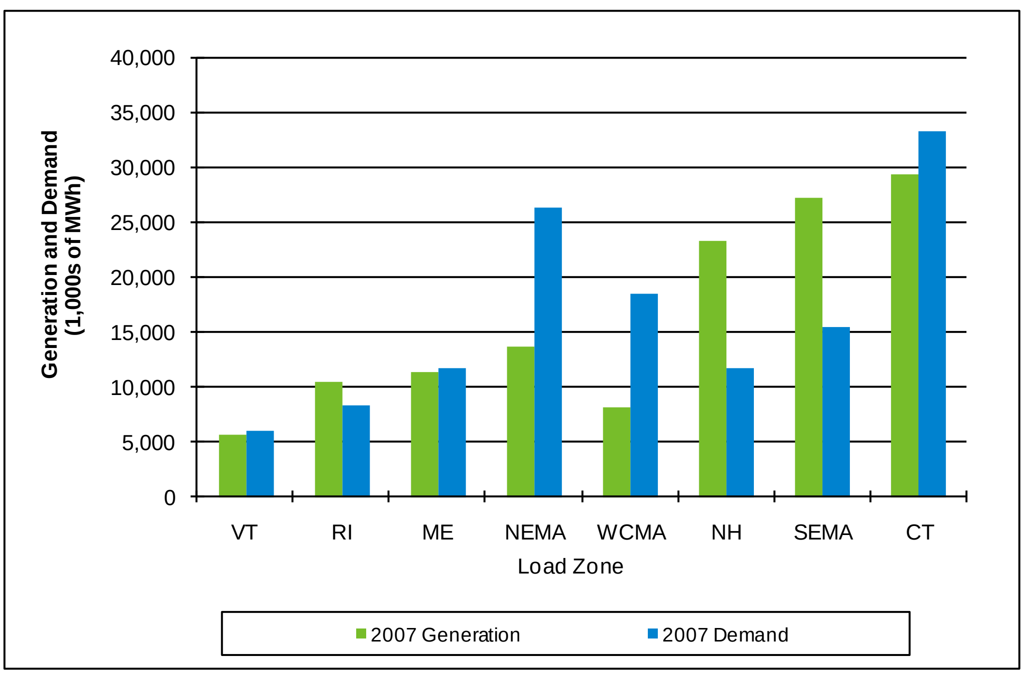

Figure 2-10: Annual generation and electric energy demand by load zone.

2.3.2 Generation by Fuel Type

Figure 2-11 shows actual generation by fuel type as a percentage of total generation for 2003 through 2007. The figure shows the fuels used to generate electric power, which differ from the capacity fuel mix shown in Figure 2-9 and the marginal unit by fuel type shown later in Figure 2-18 (see Section 2.4.2). The percentage of total generation produced by gas-fired and gas- and oil-fired plants in New England was 42% in 2007. Nationwide, about 21% of electric energy is produced by power plants fueled by natural gas.[42]

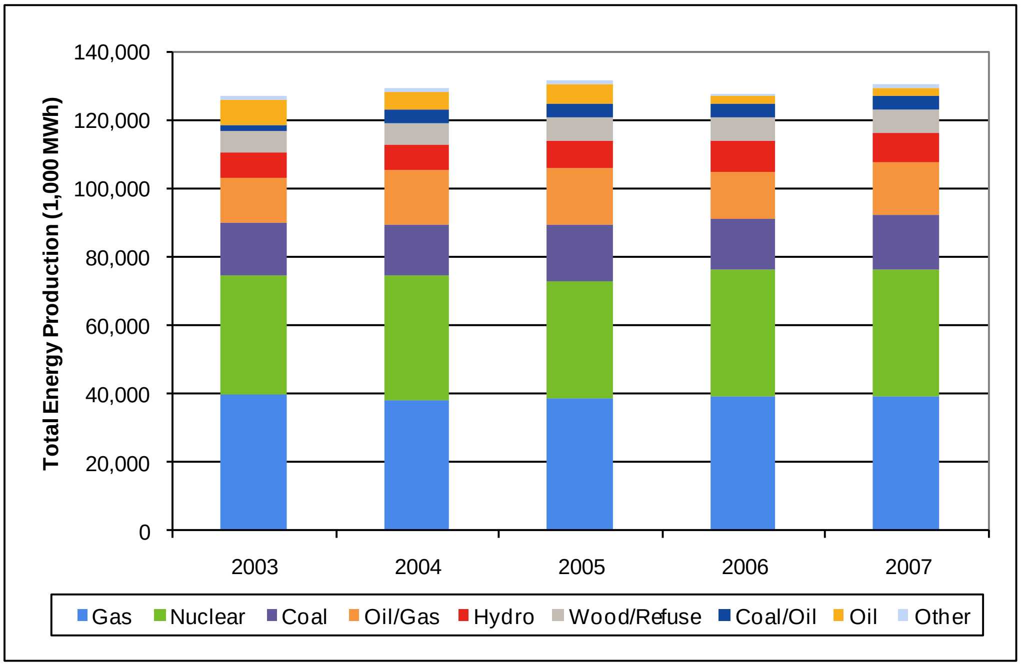

Figure 2-11: New England generation by fuel.

Note: "Other" includes jet fuel, diesel, composite, small renewables, and other small generation.

As discussed in Section 2.2, NEL increased by 1.9% from 2006 to 2007. Overall, 2007 generation increased 2.1%, from 128,046,000 MWh in 2006 to 130,720,000 MWh in 2007. Net imports from other control areas declined, accounting for the difference between changes in NEL and generation. During 2007, net imports from other control areas totaled 6,117,000 MWh, or about 4.5% of NEL.

2.3.3 Renewable Portfolio Standards in New England

Five of the six New England states (all but Vermont) have Renewable Portfolio Standards (RPSs) to encourage the development of renewable resources in the region. New Hampshire is the most recent state to establish a standard and is in the process of promulgating RPS regulations, which will go into effect sometime in 2008. Several states have other related requirements for the growth of renewable resources and energy efficiency. Vermont and Maine have newly established renewable requirements outside the RPS structure. Connecticut has new growth requirements for energy-efficiency programs, and Massachusetts recently announced energy-efficiency goals.

The Renewable Portfolio Standards in the New England states require a certain percentage of the electric energy produced or purchased by utilities to be from designated types of renewable resources

[42] EIA 2008. *Short-Term Energy Output.* Available online at http://www.eia.doe.gov/steo. (Accessed January 29, 2008).

over the next five years or more. This percentage typically increases annually up to a specified level. General types of resources the states qualify as renewable include small hydro, solar, wind, biomass, landfill gas, ocean thermal, and, in some states, fuel cells.[43] Some specific types unique to each state's RPS exist as well. The RPSs are intended to stimulate the development of new renewable resources and achieve a more diverse and "clean" generation portfolio.

To meet their renewable energy requirements, suppliers may buy Renewable Energy Certificates (RECs) created at renewable facilities within the New England region.[44] Alternatively, they may own and operate such resources to create RECs. Suppliers that do not meet their state's RPS requirements with generation are required to make Alternative Compliance Payments (ACPs) to cover the gap. These funds are to be used to invest in renewable projects within the state. These standards do not apply to municipal utilities.

Maine, Connecticut, and Massachusetts implemented RPSs before other states in the region. Rhode Island implemented its RPS in 2007, and Vermont, which passed a state law in 2005, is implementing its regulations for renewables. A number of other northeastern states, including New York, New Jersey, and Pennsylvania, also have implemented RPSs.

The specific percentages of electric energy that suppliers must obtain from renewable sources vary by state and year, as do the types of resources that qualify as renewable. The RPS requirements in 2007 were 5% for Connecticut suppliers, 2.5% for Massachusetts suppliers, 30% for suppliers in Maine. Rhode Island's RPS requirements started in 2007 at 3%. Vermont's requirement covers just incremental growth from 2005 to 2015. By 2015, the RPS requirements will increase to 14% in Connecticut, 10% in Massachusetts, and 10% in Rhode Island. The requirement in Maine will remain at 30%.

In 2007, renewable resources in New England generated about 10% of the region's total electricity. These resources included wind, refuse, landfill gas, biomass, and hydroelectric generators, excluding hydro generators that use pumping facilities to store the water source. The ISO's *2007 Regional System Plan* (RSP07) indicates that the New England renewable projects in the ISO Generator Interconnection Queue will not provide sufficient energy to meet the aggregate RPS energy requirements set for New England for 2016.[45] Unless many smaller projects are installed and operating by 2016, or renewable projects outside New England are certified for meeting the New England states' RPSs, the suppliers could fail to meet their RPS requirements. RSP07 contains additional information on Renewable Portfolio Standards.

2.3.4 Self-Scheduled Generation

Figure 2-12 shows the monthly percentage of total real-time generation that was self-scheduled for 2005 to 2007. 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

[43] Pumped hydro is not counted as a renewable resource because the energy for pumping comes mostly from fossil-fueled (i.e., nonrenewable) generating plants.

[44] A *Renewable Energy Certificate* represents the environmental attributes of one megawatt-hour of electricity from a certified renewable generation source for a specific state's RPS. Providers of renewable energy are credited with RECs, which are sold or traded separately from the electric energy commodity.

[45] RSP07 is available online at http://www.iso-ne.com/trans/rsp/2007/rsp07_final_101907_public_version.pdf or by contacting ISO Customer Service at 413-540-4220.

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. At times, self-scheduling contributes to Minimum-Generation Emergencies.[46] In 2007, self-scheduled generation averaged between 59% and 73% of total real-time generation, broadly consistent with past trends.

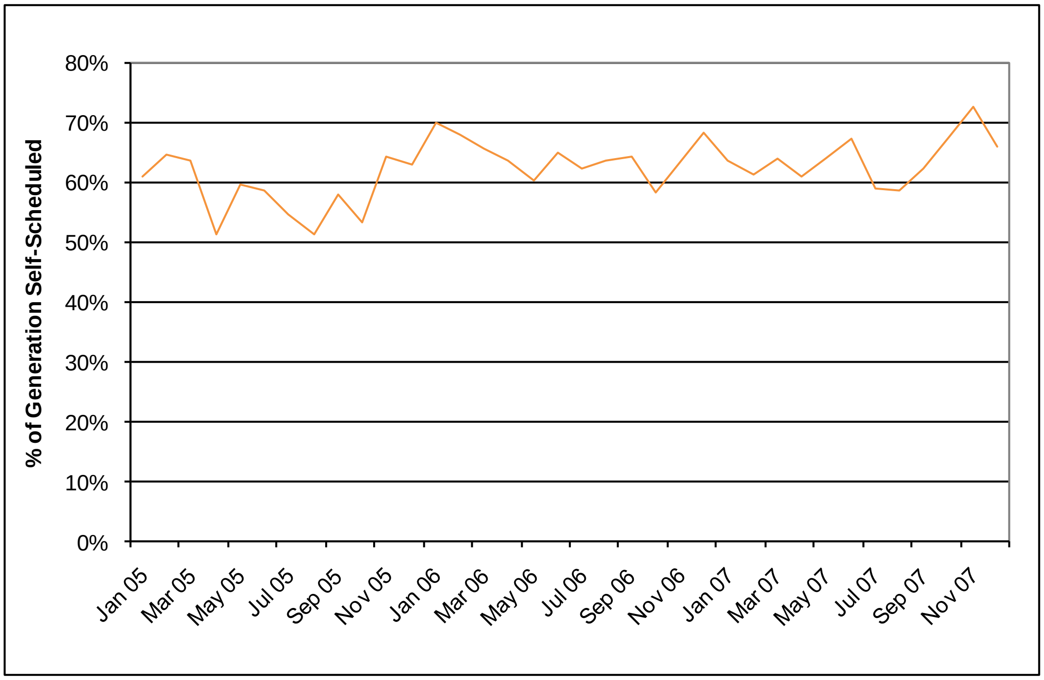

Figure 2-12: Self-scheduled generation as a percentage of total generation for 2005 to 2007.

Table 2-2 shows by generator fuel type the percentage of generation that was self-scheduled during 2007. Nuclear-fueled generators self-scheduled 100% of their generation, while coal/oil, oil, and jet fuel generators self-scheduled less than 20% of their generation. The percentage of generation self-scheduled is highest in off-peak hours and lowest in on-peak hours. This pattern suggests that participants may use self-scheduling as a tool to prevent generating units from being cycled on and off.

[46] A *Minimum-Generation Emergency* is a type of emergency declared by the ISO for which it anticipates requesting one or more generating resources to operate at or below its economic minimum limit so that it can manage, alleviate, or end the emergency.

Table 2-2
Percentage of Self-Scheduled Generation by Generator Fuel Type, 2007

Generator Type	% of Generation
Oil	10
Coal/Oil	15
Jet Fuel	19
Gas	40
Oil/Gas	45
Coal	67
Wood/Refuse	77
Hydro	82
Diesel Oil	94
Nuclear	100

2.3.5 Imports and Exports

During 2007, New England remained an overall net importer of power; its net imports from Canada exceeded the net exports to New York. Net interchange with neighboring regions amounted to 6,113,000 MWh for the year, about in line with net interchange in 2006. In 2007, both net imports from Canada and net exports to New York increased. Figure 2-13 shows net interregional power flows for 2003 through 2007, and Figure 2-14 shows imports and exports by interface for 2007.

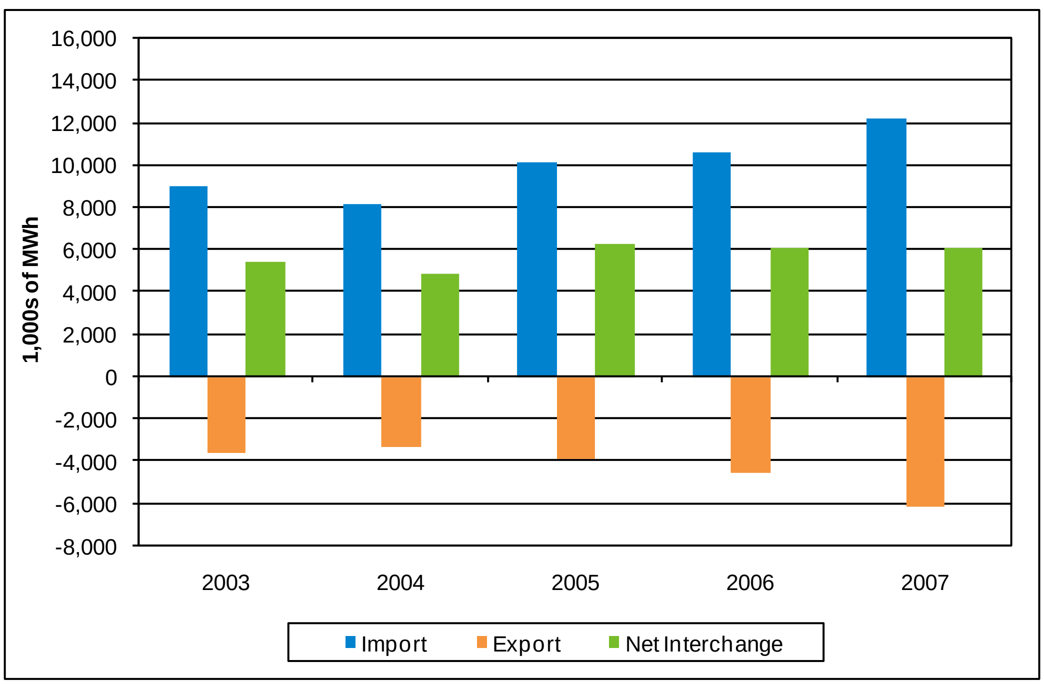

Figure 2-13: New England annual imports, exports, and net interchange, all interfaces.

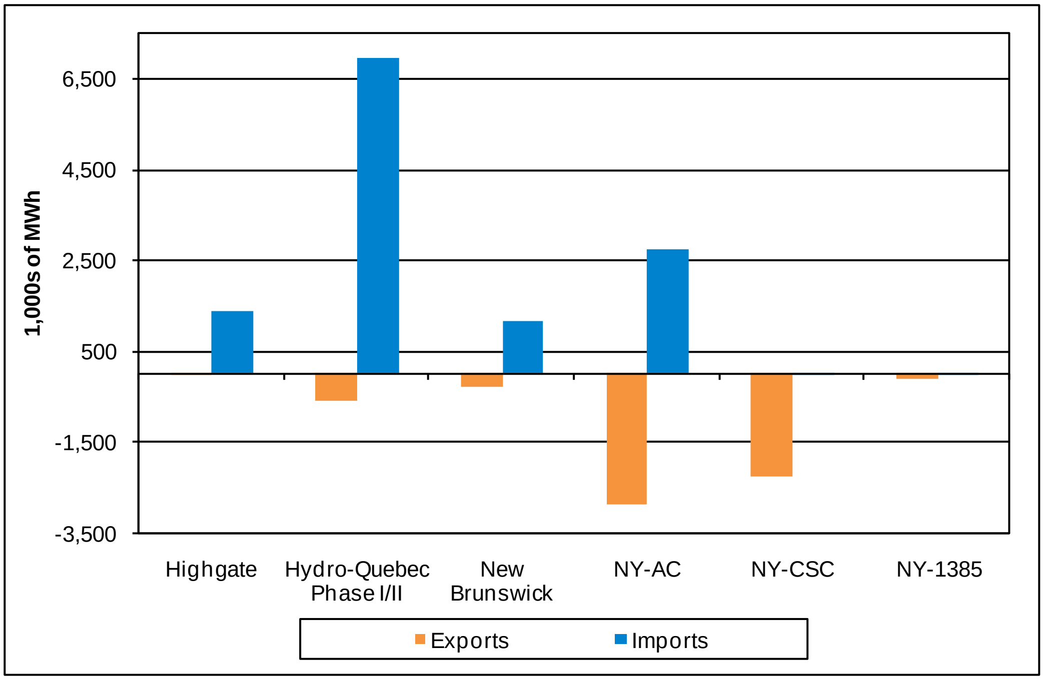

Figure 2-14: New England imports and exports by interface, 2007.

Note: The New York-AC interface is the collection of AC tie lines connected through Connecticut, Massachusetts, and Vermont. The NY-CSC interface is the Cross-Sound Cable.

Participant energy trading between New England and eastern and northern New York (i.e., on the NY-AC interface) exhibits bidirectional patterns (imports and exports), while trading over the CSC always is an export to Long Island associated with a long-term contract. Most of the power transfers between New York and New England are the result of contracts, in particular long-term contracts for exports over the CSC.

In June 2007, the ISO implemented the 1385 cable external node (Northport–Norwalk Harbor), establishing an external node unique to the 1385 cable. This node allows market participants to request electric energy schedules for delivery to New England specifically over this facility and for the specific pricing of that energy. With the creation of this external node, the region has three NY–NE interfaces (Cross-Sound Cable, 1385 cable, NY Northern AC). Although the new pricing and scheduling node was implemented in June, the cable went out of service in early August so that it could be replaced, and it did not return to service during 2007.

2.3.6 Operable Capacity Margins

The *operable capacity margin* is the sum of generating capacity and net imports minus the sum of load and reserve requirements. The capacity margin includes generation that may have been unavailable because of start-up time requirements, subarea export constraints, or a combination of both.[47]

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[47] To conduct resource planning reliability studies within New England, the region is modeled as 13 subareas and three neighboring control areas. These areas include northeastern Maine (BHE); western and central Maine/Saco Valley, New Hampshire (ME); southeastern Maine (SME); northern, eastern, and central New Hampshire/eastern Vermont and southwestern Maine (NH); Vermont/southwestern New Hampshire (VT); Greater Boston, including the North Shore

In summer 2007, the operable capacity margin was higher than in previous years. Figure 2-15 shows operable capacity margins for the peak-demand hour of each month for 2005 to 2007. As usual, margins were lower during the summer months than in other months, which is consistent with summer-peak demand. The unseasonably high margins in July and August 2007 were due to monthly peak demand levels that were lower than usual.

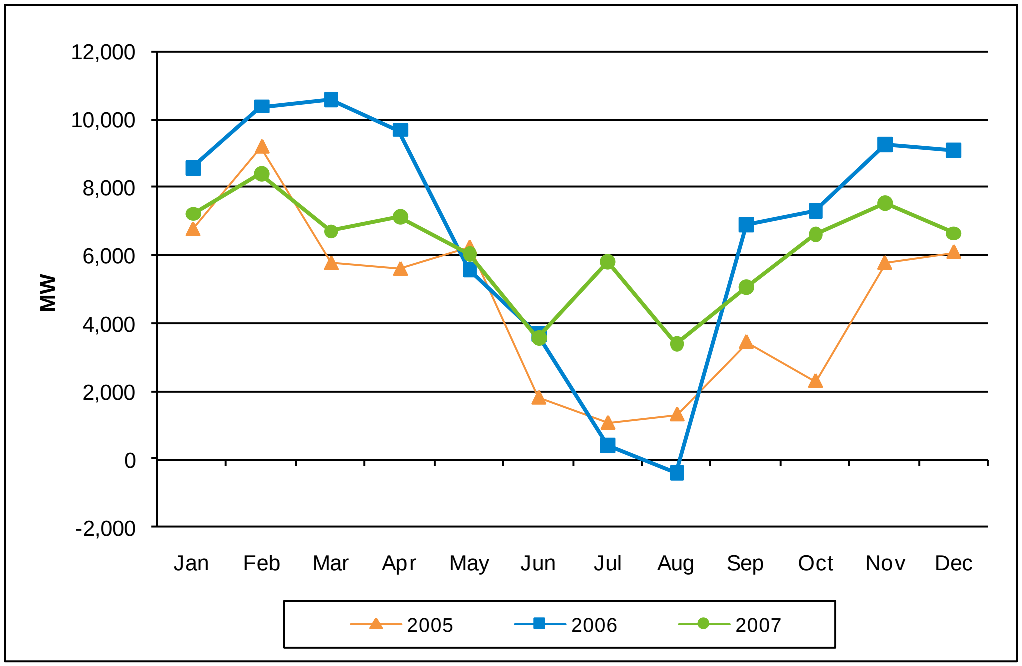

Figure 2-15: Monthly peak-hour operable capacity margins for 2005 through 2007.

2.4 Electric Energy Prices in 2007

This section provides information about wholesale electricity prices in New England, including the impact of fuel costs on prices, price separation between load zones, and capacity deficiencies that resulted in price spikes.

2.4.1 Annual Real-Time Electric Energy Prices

Figure 2-16 and Figure 2-17 show the real-time system electricity price for New England over the past five years as duration curves with prices ordered from highest to lowest. The system price is the load-weighted Real-Time Energy Market LMP. For each year, the duration curve shows the percentage of time the system price was at or above the price levels shown on the vertical axis.

(BOSTON); central Massachusetts/northeastern Massachusetts (CMA/NEMA); western Massachusetts (WMA); southeastern Massachusetts/Newport, Rhode Island (SEMA); Rhode Island bordering Massachusetts (RI); Southwest Connecticut (SWCT); Norwalk/Stamford (NOR); and Connecticut (CT). Greater Connecticut includes the CT, SWCT, and NOR subareas. Greater Southwest Connecticut consists of the SWCT and NOR subareas. The three neighboring control areas are New York, Hydro-Québec, and the Canadian Maritimes. The New England Control Area also is divided into load zones and reserve zones, explained more fully in Section 2.1 and Section 4.1, respectively.

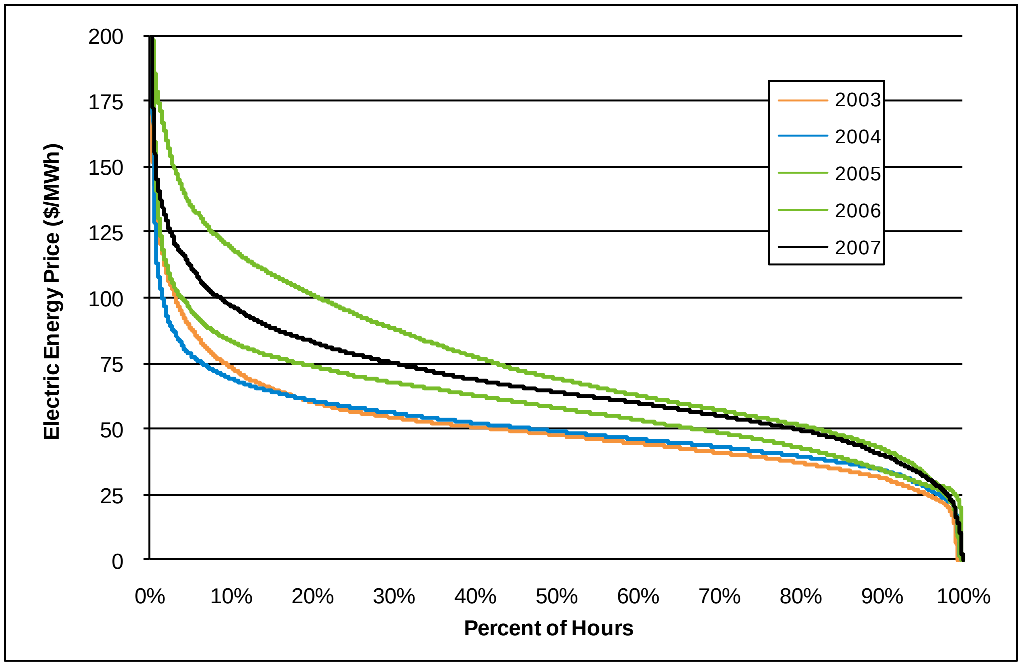

Figure 2-16: System real-time price-duration curves, prices less than $200/MWh, 2003 to 2007.

Note: System price is the single energy-clearing price (ECP) for the Interim Market period ending February 28, 2003, and load-weighted Real-Time Energy Market LMPs for March 2003 to December 2006.

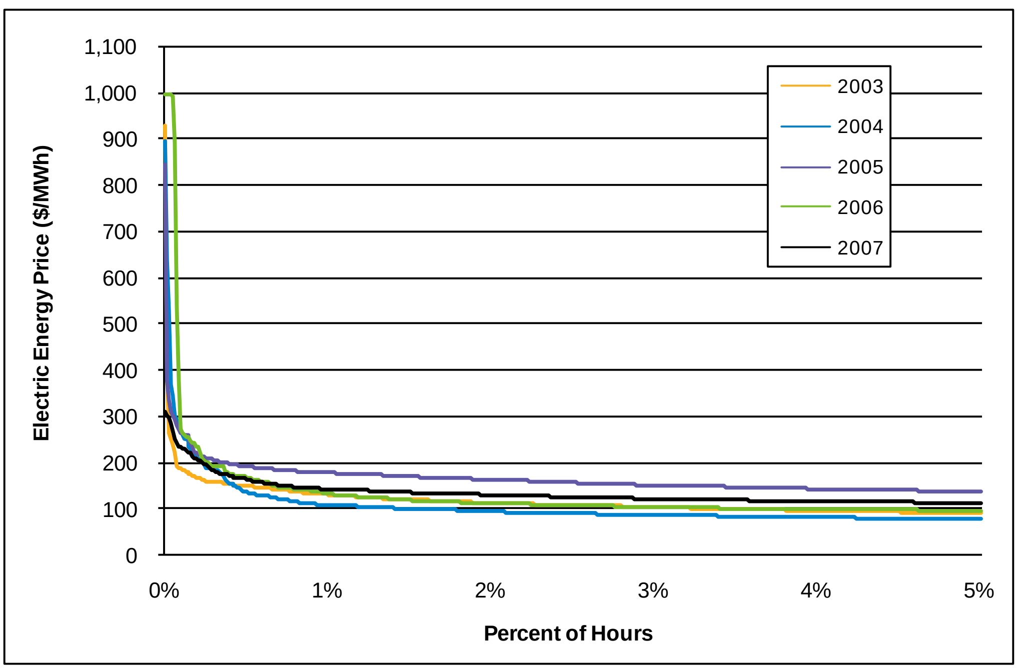

Figure 2-17: System real-time price-duration curves, prices in most expensive 5% of hours, 2003 to 2007.

Note: System price is the single ECP for the Interim Market period ending February 28, 2003,and load-weighted Real-Time Energy Market LMPs for March 2003 to September 2007.

The figures show that typical prices during 2007 were higher than prices during 2006 but lower than those in 2005. The increase from 2006 primarily was due to increased fuel prices (as discussed in the next section). The peak prices shown in Figure 2-17 were lower than in both 2006 and 2005. This is consistent with the higher operable capacity during summer peak periods discussed in Section 2.3.6. Appendix A.2 includes LMP summary statistics for on- and off-peak hours and the monthly average day-ahead and real-time LMPs by zone.

2.4.2 Electricity Prices and Fuel Costs

Electric energy prices were slightly higher in 2007 than in 2006 primarily due to a rise in fuel prices. Other factors that affected the price of electric energy in 2007 include a higher use of electric energy (net energy for load), fewer Minimum-Generation Emergency hours when prices are set to zero, and the institution of co-optimization of reserves with electric energy. Gas-fired generation continues to be the marginal resource most of the time. In 2007, gas-fired resources were marginal 72% of the time, similar to 2006 when gas was marginal 73% of the time.

This similarity, however, masks a deeper change in fuel costs. During 2007, liquid fuel prices (No. 2 oil, jet kerosene, No. 6 oil) increased more than natural gas prices, building on a trend observed in 2006 of a widening gap between the cost of natural gas and liquid fuels. This change in relative prices affects generator dispatch by shifting liquid-fueled generators to a later point in the dispatch stack and substituting natural gas resources that otherwise would have been out of merit. The result is a steeper dispatch curve—a dispatch stack that rises in cost sooner. In this new environment, natural gas combined-cycle resources are providing a lower-cost alternative to liquid-fueled resources.

2.4.2.1 Marginal Units

Because the price of electricity changes as the price of the marginal fuel changes, analyzing marginal units by fuel type helps explain this electricity price factor. In all circumstances, the system has one marginal unit that is classified as the *unconstrained* marginal unit. In a locational marginal pricing market, however, more than one resource sets price 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 local generation would need to be *dispatched up* to meet load. In this instance, the local unit dispatched up would be considered *constrained up for transmission* because, absent the limit on the interface, it would otherwise be off or dispatched at a lower level. For some transmission-constraint conditions, the ISO lowers the output of a marginal unit, which then is classified as *constrained down for transmission*.

Figure 2-18 shows the percentage of total marginal minutes that each input fuel was marginal during 2007. If there are two marginal units during a single five-minute interval, the analysis counts 10 marginal minutes. Using this methodology, the sum of marginal minutes across all input fuels will equal 100%.

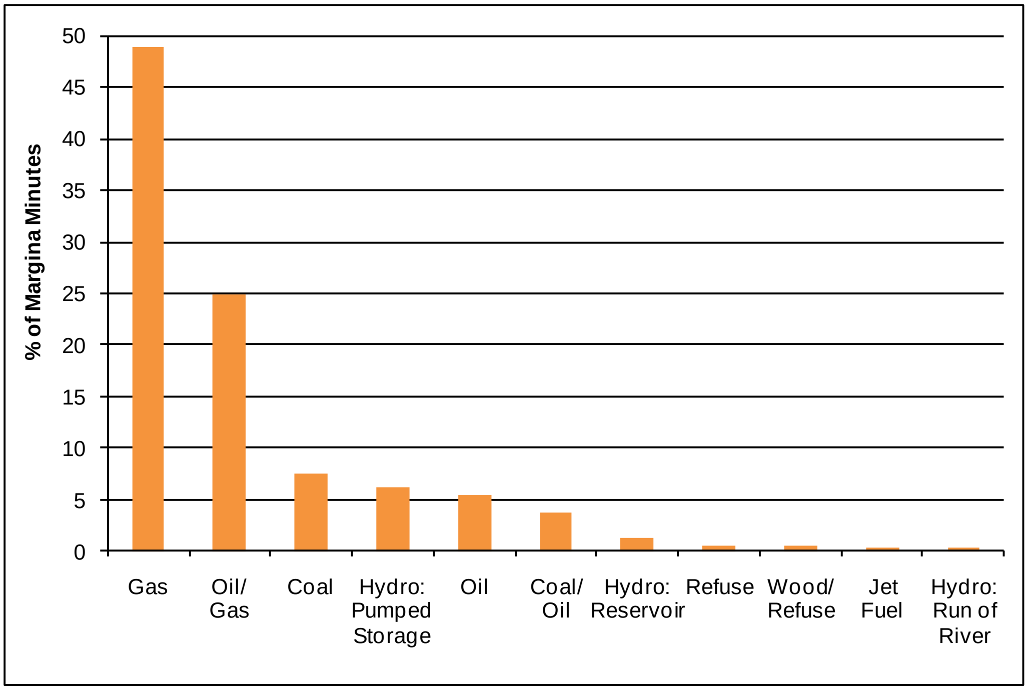

Figure 2-18: Percentage of pricing intervals by marginal fuel type in real time, 2007.

Note: The figure includes each marginal unit; during periods 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. Diesel-fueled units were marginal during the year for less than 1/10 of a percent of the total marginal minutes. This fuel source is not included in the figure.

Figure 2-18 shows that a unit burning natural gas was marginal during 49% of all the marginal minutes. Units capable of burning both gas and oil, most of which burn gas as their primary fuel, accounted for 25% of all marginal minutes. These results show the extent to which New England electricity prices depend on the offers of units capable of burning natural gas. The data presented in Figure 2-18 demonstrate that almost 80% of all minutes marginal are from natural-gas-fired or oil-fired units. This dependence on gas and oil to generate electricity contributes to the year-to-year volatility of the region's electricity price.

2.4.2.2 Relative Fuel Prices

The marginal fuel types have remained relatively constant between 2006 and 2007. However, the relative fuel prices changed significantly because of the rise in petroleum prices. In the last week of 2006, the average cost of imported crude oil was $54/barrel. This rose to $85.52/barrel in the last week of 2007.[48] Geopolitical concerns and uncertainty in financial markets have contributed to rising oil prices over most of the year.[49] The decline of the dollar against most other currencies has contributed to the rise in prices because most U.S. oil is imported.

Table 2-3 shows indices for average annual prices of several fuels for each of the last eight years, with each fuel indexed to its value in 2000. Generators that burn natural gas and No. 6 oil set price a majority of the time in New England, as shown in Figure 2-18. Natural gas prices were 8.8% higher

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[48] Weekly crude prices are available at http://www.eia.doe.gov/.

[49] Energy Information Administration. *Residential Natural Gas Prices What Consumer Should Know*. DOE/EIA-X046 (Washington, D.C.: U.S. DOE; 2007). Available online at http://www.eia.doe.gov/neic/brochure/oil_gas/rngp/index.html.

in 2007 than in 2006. No. 6 oil (1%) increased 16.2%. The higher natural gas and oil prices were the primary cause of the higher overall electricity prices shown in Figure 2-16.

Table 2-3
Fuel Price Index, Year 2000 Basis

Fuel	2000	2001	2002	2003	2004	2005	2006	2007
Natural gas	1	0.88	0.75	1.3	1.37	1.97	1.48	1.61
No. 2 oil	1	0.84	0.8	0.99	1.32	1.95	2.15	2.43
No. 6 oil (1%)	1	0.83	0.9	1.09	1.12	1.66	1.85	2.15
High-sulfur coal	1	1.72	1.11	1.32	2.22	2.38	2.02	1.83
Low-sulfur coal	1	1.76	1.15	1.35	2.35	2.49	2.22	1.91
Jet fuel	1	0.82	0.78	0.95	1.31	1.87	2.14	2.37
Kerosene	1	0.82	0.77	0.95	1.31	1.89	2.15	2.38
Diesel	1	0.84	0.8	0.98	1.33	1.97	2.27	2.50

During recent years, petroleum prices have grown faster than natural gas prices. Figure 2-19 shows the relative prices for No. 2 and No. 6 oils and natural gas normalized to year 2000 prices. The spike in gas prices in 2005 is attributed to the supply interruptions of hurricanes Katrina and Rita.

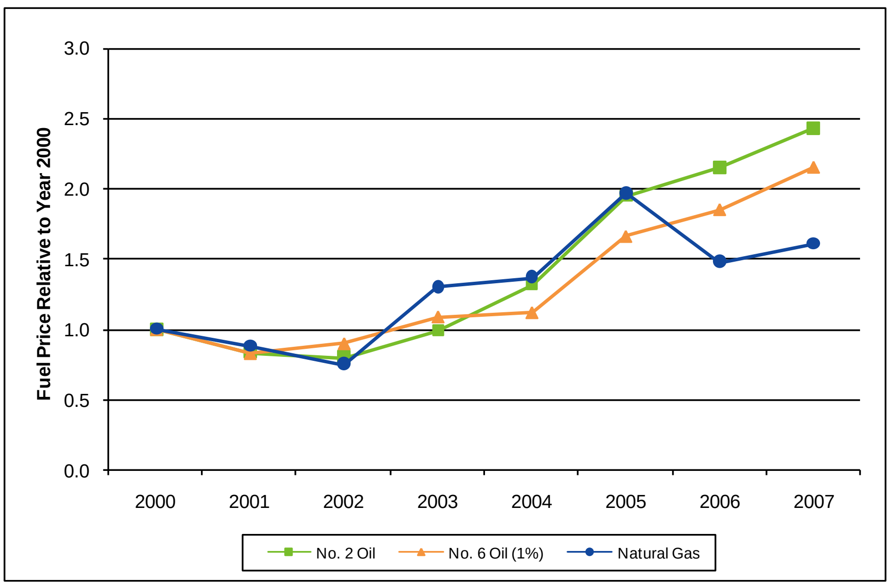

Figure 2-19: Growth in fuel prices relative to year 2000 prices.

Figure 2-20 shows the daily average real-time system price plotted against the daily average variable production cost of hypothetical power plants burning either natural gas or No. 6 oil.[50] The gas resource marginal costs are based on a combined-cycle gas resource with a heat rate of 7,500 British

[50] Averages are not weighted.

thermal units (Btu) per kilowatt-hour (kWh), while the oil resource production costs are based on a heat rate of 10,500 Btu/kWh.[51] The day-ahead spot prices for fuel are used to calculate each unit's variable costs. Unexpected system conditions, such as an unplanned generator or transmission line outage, or unexpected high demand levels may cause electricity price spikes unrelated to fuel prices.

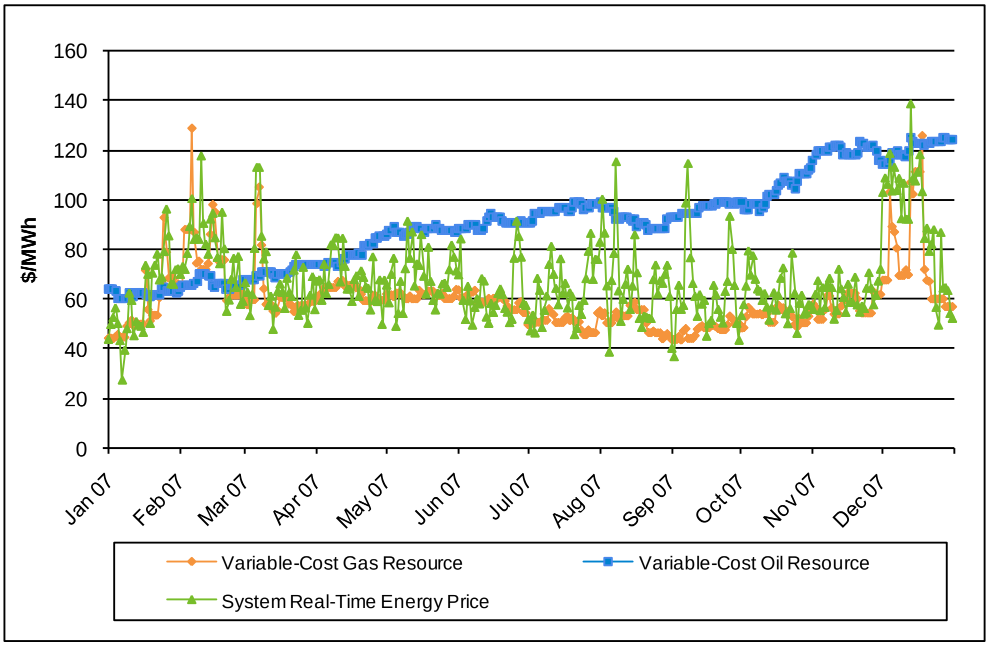

Figure 2-20: Daily average real-time system price of electricity compared with variable production costs.

During many days in January and February 2007, the hypothetical No. 6 oil unit shown in Figure 2-20 would have had costs less than the real-time system price and less than the gas unit's costs. However, the costs of No. 6 oil rose almost continuously during the year, and the No. 6 oil unit would have been more often out of merit relative to the system price as the year progressed.

The change in the merit status of No. 6 oil units relative to natural gas units affected the underlying supply curve. Before the increase in the cost of No. 6 oil, some oil units offered at the same level as some efficient combined-cycle natural gas units. As the cost of oil increased by more than the cost of natural gas did, some No. 6 oil units have been displaced by less efficient (i.e., higher heat rate) natural gas units.

Figure 2-21 illustrates the effect of the increased prices of No. 6 oil and other liquid fuels on the marginal cost supply curve while holding the natural gas price constant. The supply curve is limited to fossil fuel resources; it excludes nuclear, hydro, and other nonfossil fuels. The higher of the two curves represents the 2007 supply curve using average 2007 fuel prices. The lower of the two curves uses the same heat rates and megawatt blocks as the 2007 supply curve but uses fuel costs that have normalized 2004 prices to the 2007 price of natural gas. To normalize the 2004 fuel prices, the 2004 price of each fossil fuel was multiplied by the ratio defined by the 2007 average natural gas price divided by the 2004 average natural gas price.

[51] 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.

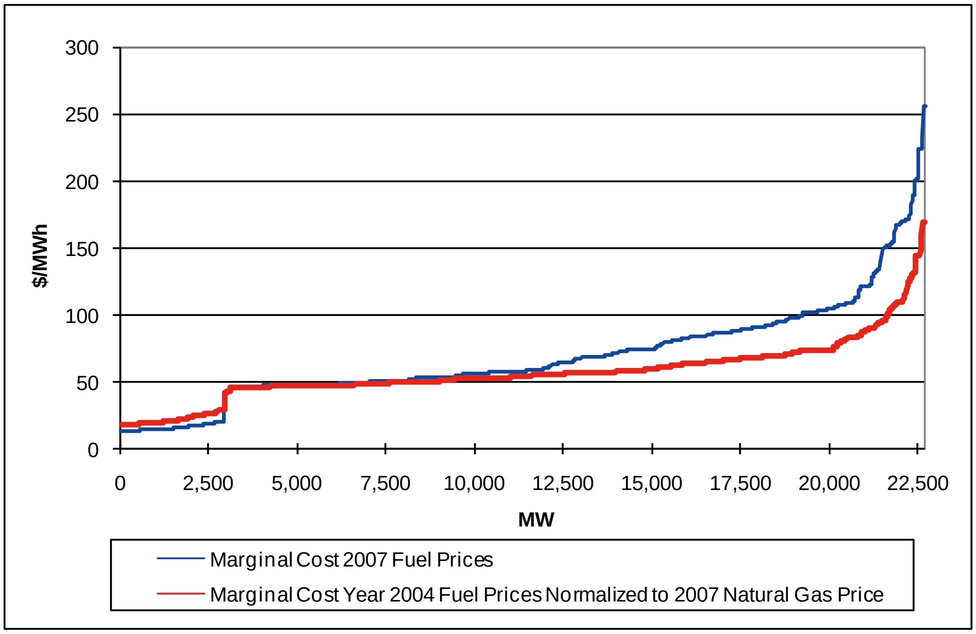

Figure 2-21: Effect of increased fuel prices of No. 6 oil and other liquid fuels on marginal cost supply curve while holding natural gas prices constant.

Note: Fuel costs are annual averages. The 2004 fuel costs are normalized to 2007 gas prices.

Figure 2-22 illustrates the change in the relative merit order of No. 6 oil resources offering at marginal cost. The data here are from the same supply curves illustrated in Figure 2-21, but Figure 2-22 presents only those blocks associated with No. 6 oil. The No. 6 oil resources are uniformly higher in the stack than they would be if the price of No. 6 oil had risen at the same rate as the price of natural gas. The marginal cost of a combined-cycle gas resource operating at a heat rate of 7,500 Btu/kWh is included as a benchmark.

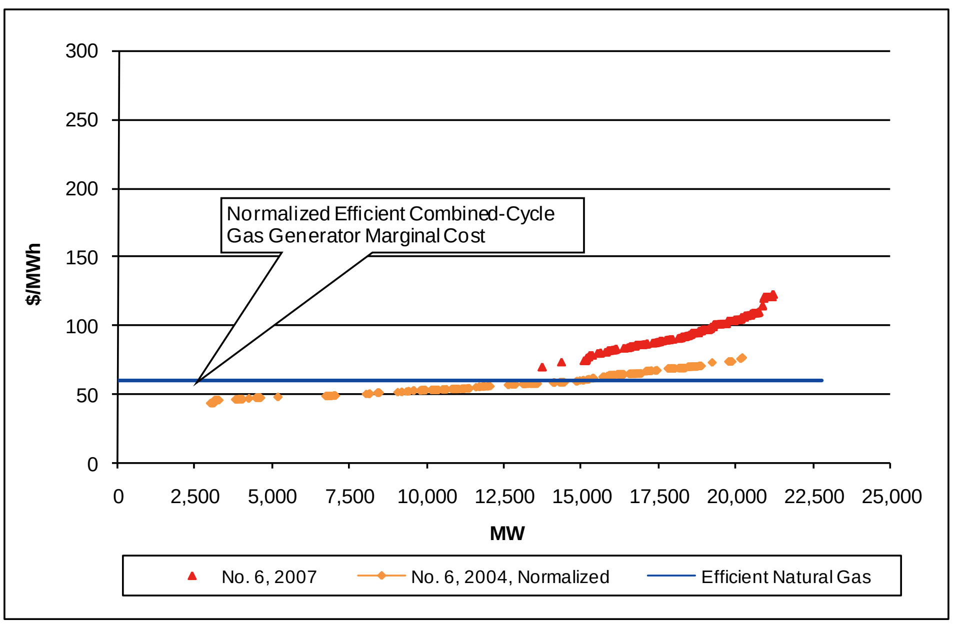

Figure 2-22: No. 6 oil generator marginal costs using 2007 actual and 2004 normalized fuel prices.

Figure 2-22 confirms that No. 6 oil resources competed with natural gas resources much less often in 2007 than in 2004. The dispatch order and supply curves have changed as a result of the relative price changes.

2.4.2.3 Fuel-Adjusted Electric Energy Price

The ISO historically has calculated a "fuel-adjusted" electricity price using a simple methodology, recognizing its limitations. The analysis uses the year 2000 as a base and normalizes the price of the marginal unit in each five-minute interval for the change in the unit's fuel price compared with fuel prices in 2000. This marginal unit methodology assumes that the marginal units are similar in all years. In contrast, the analysis surrounding Figure 2-20 through Figure 2-22 shows that marginal units have changed significantly.

Fuel-adjusted electric energy prices for the Interim Markets period of January 2000 through February 2003 were derived by adjusting each five-minute real-time marginal price (RTMP) by a monthly index of spot-market prices for the fuel used by the generator setting the RTMP. Fuel-adjusted electric energy prices for the Standard Market Design (SMD) period of March 2003 through December 2007 were derived by adjusting the five-minute Hub real-time LMPs by a monthly index of spot-market prices for the fuel used by the marginal generator. This generator was not constrained up or down for transmission in the Unit Dispatch System (UDS) case that formed the basis for the LMP.

Five-minute prices set by hydro plants in 2007 were adjusted by a monthly index of average electric energy prices to reflect changes in opportunity costs. Nuclear, wood, composite, refuse, and other fuels for which reliable prices were not available were not adjusted. These unadjusted prices should not significantly affect the results because units using these fuels were marginal less than 1% of the time during the seven-year analysis period. The adjusted five-minute electric energy prices were then averaged to the hourly level and weighted by hourly load before calculating the yearly averages.

Table 2-4 and Figure 2-23 show yearly average actual and fuel-adjusted real-time electric energy prices for New England. These averages are load weighted. Actual average real-time electric energy prices in 2007 were higher than in 2006 but lower than in 2005. After adjusting for the price of fuels used to generate electricity, the average electric energy price in 2007 was similar to prices in the previous years.

Table 2-4
Actual and Fuel-Adjusted Average Real-Time Electric Energy Prices, $/MWh

	2000	2001	2002	2003	2004	2005	2006	2007
Load-weighted actual electric energy price (ECP during Interim Markets; Hub LMP during SMD)	45.95	43.03	37.52	53.40	54.44	79.96	62.74	69.57
Load-weighted electric energy price normalized to 2000 fuel-price levels	45.95	48.60	46.65	43.51	43.33	44.99	42.64	45.15

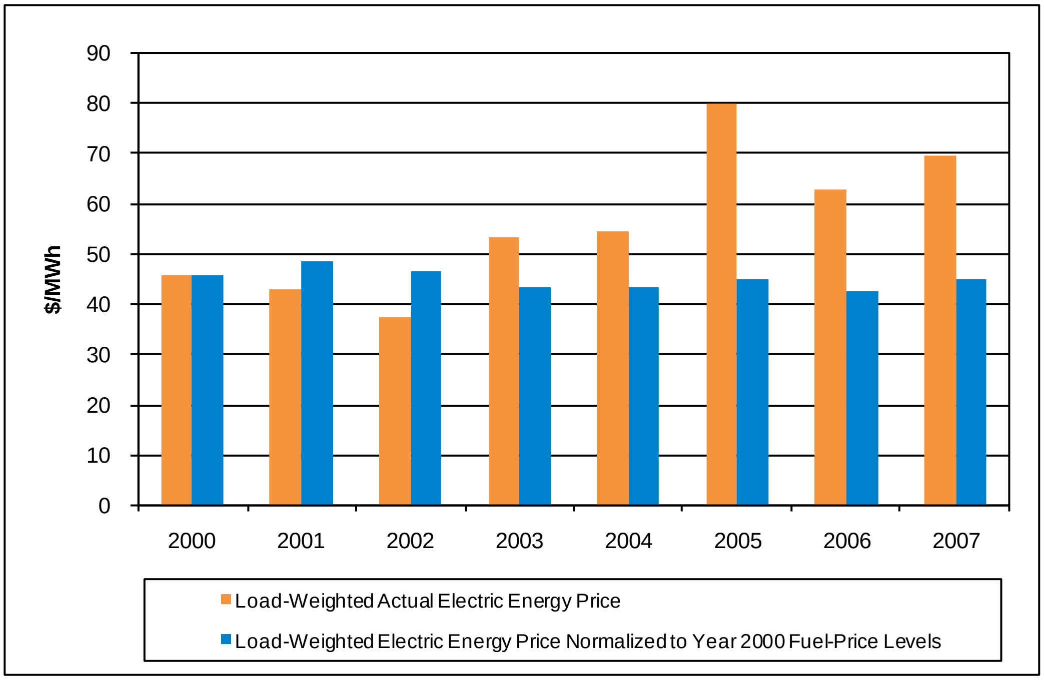

Figure 2-23: Actual and fuel-adjusted average real-time electric energy prices, 2000 to 2007.

The variation among fuel-adjusted yearly average prices was less than among average unadjusted prices. Adjusted prices in 2001 and 2002, years with lower overall natural gas prices than 2000, were higher than actual prices, while energy prices in 2003 to 2007, when gas prices were higher, were lower after adjustment.

Electric energy prices appear to be normal when adjusted for fuel prices. The fuel-adjusted price of electric energy in 2007 of $45.15/MWh was $2.51/MWh higher than in 2006. In comparison, the average fuel-adjusted price from 2000 to 2006 was $45.01/MWh. Actual unadjusted average electric energy prices rose from $62.74/MWh in 2006 to $69.57/MWh in 2007. This increase was paralleled by an 8.8% increase in natural gas prices and a 16.2% increase in the price of 1% sulfur No. 6 oil.

The size and direction of the change is consistent with the effect of increased energy demand in 2007. The ISO estimated the effect of increased demand by applying the increased demand to representative supply curves. Average hourly energy demand increased by 279 MW, yielding estimates ranging from $1.29/MWh to $4.96/MWh. The observed increase in the fuel-adjusted energy price of $2.51/MWh (5.8%) falls well within this range. Therefore, market price changes are consistent with the shifts in the underlying demand and supply conditions.

2.4.3 LMPs and Nodal Prices for 2007

Table 2-5 shows the 2007 average LMP values for the Hub and the eight load zones in New England. On average, day-ahead prices exhibited a slight premium over their real-time counterparts. During 2007, average prices were similar across the Hub and New England load zones, with the exception of Maine and Connecticut. Average LMPs in Maine were several dollars lower than in other areas, as a result of negative marginal loss and congestion components costs on Maine LMPs, while average LMPs in Connecticut were higher than in other areas. Average day-ahead LMP differences between Maine and Connecticut were $7.35/MWh. During high-demand periods, Connecticut frequently is import constrained, which results in congestion and higher prices. On average, electric energy prices in the day-ahead market should approximate their real-time counterparts. However, the slightly higher day-ahead LMPs noted in Table 2-5 are consistent with a premium that reflects the price risk of the real-time market. Load is willing to pay a little more to avoid the potentially high prices that occur more frequently in real time, and generators will want a premium to assume the risk of nonperformance in the real-time market.

Table 2-5
Average LMP Statistics by Zone for 2007, All Hours, $/MWh

Location/Load Zone	Average LMP	
	Day Ahead	Real Time
Internal Hub	67.97	66.72
Maine	64.35	63.65
New Hampshire	66.83	65.99
Vermont	69.35	68.11
Connecticut	71.70	71.75
Rhode Island	66.16	65.05
SEMA	67.95	66.19
WCMA	68.55	67.49
NEMA	66.63	65.6

In general, prices in the Real-Time Energy Market are more variable than prices in the Day-Ahead Energy Market as a result of unexpected events, such as generator and transmission contingencies or variations in the actual demand compared with the demand forecast. Table 2-6 shows the greater spread in difference between minimum and maximum day-ahead and real-time prices for the Hub and each load zone in 2007. For all pricing locations shown, the minimum real-time price is lower than the minimum day-ahead price, and the maximum real-time price is greater than the maximum day-ahead price. In 2007, maximum hourly prices never reached $1,000/MWh in the Day-Ahead Energy Market or the Real-Time Energy Market.

Table 2-6
Minimum and Maximum Annual Average LMPs, 2007

Location/ Load Zone	Minimum LMP		Maximum LMP	
	Day Ahead	Real Time	Day Ahead	Real Time
Internal Hub	25.18	0.00	207.35	297.92
Maine	21.47	0.00	194.99	817.08
New Hampshire	24.62	0.00	188.47	497.85
Vermont	24.94	0.00	195.82	300.39
Connecticut	24.73	0.00	205.40	631.65
Rhode Island	24.85	0.00	206.04	294.40
SEMA	24.98	0.00	208.45	295.71
WCMA	25.16	0.00	206.96	300.10
NEMA	24.69	0.00	209.08	331.76

Most of the largest differences between day-ahead and real-time prices occurred during ISO Operating Procedure 4, *Actions during a Capacity Deficiency* (OP 4) events.[52] The largest difference between day-ahead and real-time prices occurred on February 10, in hour ending (HE) 10 (10:00 a.m.).[53] OP 4 was in effect at the time, and the day-ahead price was $99.31/MWh, while the real-time price was $297.92/MWh, a difference of $198.61/MWh. The high maximum price for the Maine load zone occurred when a transmission line was out of service at the same time a generator experienced an unexpected outage.

On the maps in Figure 2-24, the average annual nodal LMPs are shown as color gradations from blue, representing $51/MWh or less, to red, representing prices of $77/MWh and higher.[54] Western Connecticut and Southeast Massachusetts had the highest average day-ahead prices, while Maine had the lowest prices. Day-ahead and real-time LMPs in northwestern Connecticut are higher than in most other areas because of a persistent loss component associated with one of the NY-AC interface tie lines.

[52] ISO OP 4 establishes procedures and guides for actions during capacity deficiencies. Actions 1–5 and 7–10 are implemented to maintain operating-reserve requirements. Action 6 allows for the depletion of 30-minute reserve, while Action 11 involves arranging to purchase emergency capacity. Actions 12 and 13 call for implementing various levels of voltage reductions.

[53] LMPs are based on *hour endings*, which denote the preceding hourly time period. For example, “hour ending 1” is the time period of 12:01 a.m. to 12:59 a.m.

[54] The extreme minimum and 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 $77.55/MWh, and the true minimum was $47.80/MWh. The actual maximum for the real-time market was $78.57/MWh, and the actual minimum was $41.81 $/MWh.

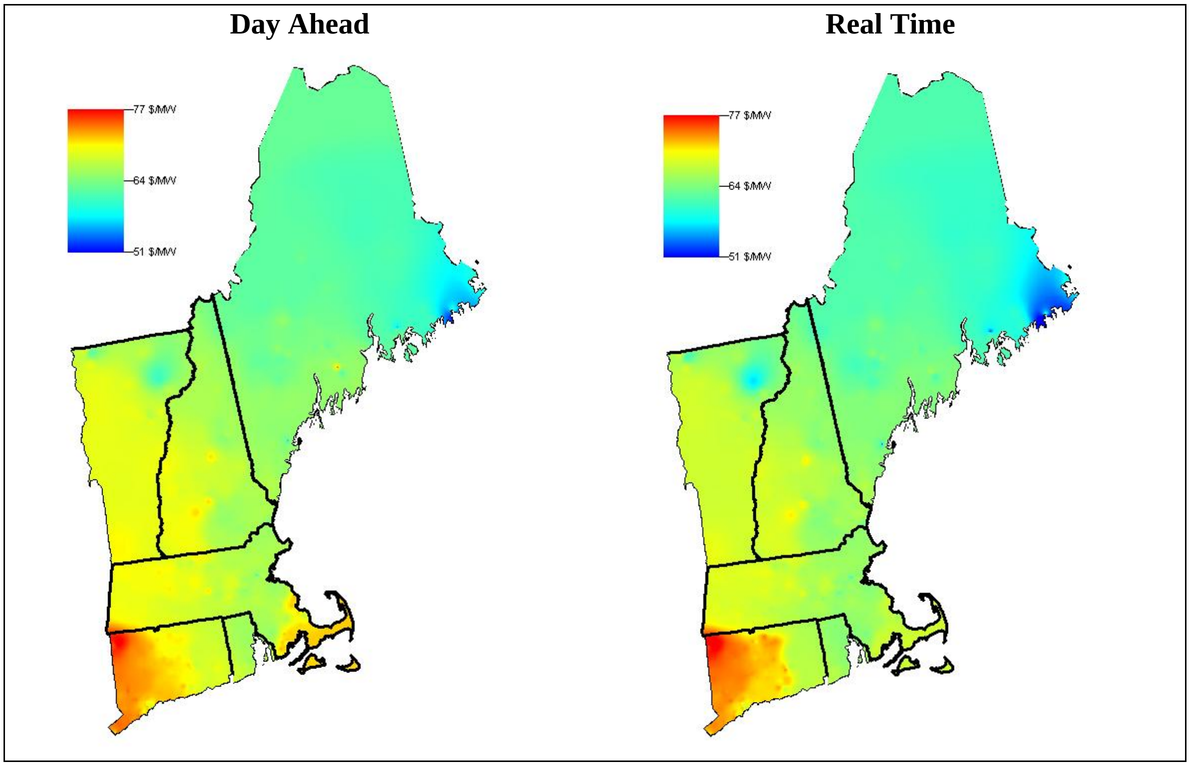

Figure 2-24: Average nodal prices, 2007, $/MWh.

2.4.4 Wholesale Prices in Other Northeastern Pools

Comparing price levels across interconnected power pools provides a context for evaluating price levels in New England. Figure 2-25 compares the 2006 average system prices with the 2007 prices for the three northeastern ISOs—ISO New England, the New York ISO (NYISO), and PJM Interconnection. The average prices for 2007 were moderately higher in all three pools (PJM real-time prices excepted). 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.[55] New York had the highest average prices, while PJM had the lowest.

[55] Yearly average system prices are not load weighted. See PJM's Web site at http://www.pjm.com and NYISO's Web site at http://www.nyiso.com.

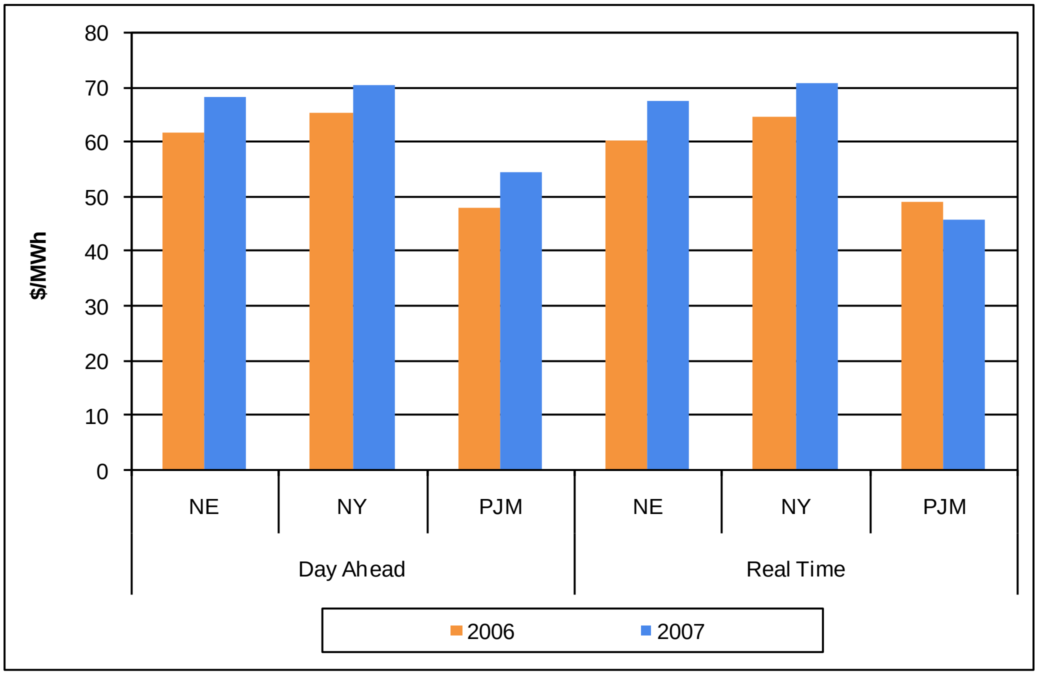

Figure 2-25: Average system prices, 2006 and 2007, ISO New England, NYISO, and PJM.

The variation in average prices among the power pools is affected by a variety of factors, such as transmission congestion, daily and seasonal demand patterns, load concentration in congested areas, and differences in the generator fuel mix. Significant coal and nuclear capacity in the PJM Control Area is a key driver of its lower average system price.[56] Appendix A.3 shows the yearly average system prices for on- and off-peak periods for ISO New England, NYISO, and PJM.

2.4.5 Comparison with Bilateral Prices

In addition to buying and selling electricity through the ISO-administered markets, participants trade electric energy bilaterally through a variety of avenues. These include the Intercontinental Exchange (ICE), an electronic marketplace for energy trading. This section presents comparisons between ISO energy market prices and ICE prices. Convergence of bilateral trading prices with wholesale market prices is an indicator of efficient markets.

Figure 2-26 shows day-ahead Hub LMPs and ICE day-ahead trade prices. The price trends generally are similar. The average difference between ISO and ICE prices for the days that power was traded is $0.41/MWh.[57]

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[56] PJM Interconnection. *Capacity by Fuel Type* (December 31, 2006). Available online at http://www.pjm.com/services/system-performance/downloads/capacity-by-fuel-type-2006.pdf.

[57] This number is the simple average of the difference between ISO and ICE prices. It indicates that, on average, ICE day-ahead trade prices were higher than ISO day-ahead LMPs.

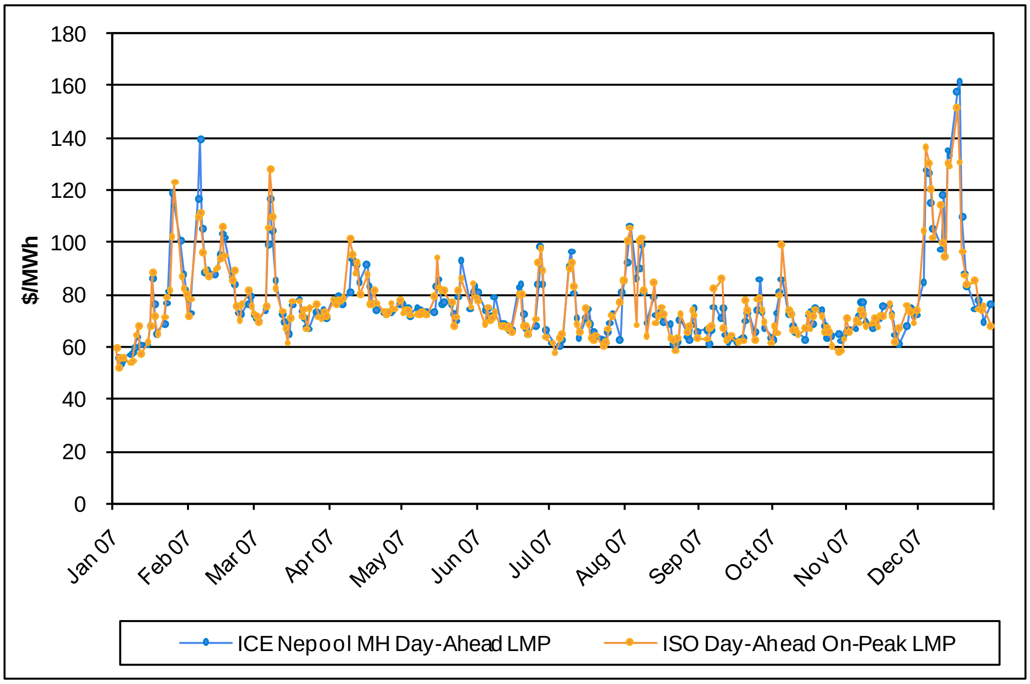


Figure 2-26: Comparison of ISO day-ahead Hub LMPs with ICE day-ahead New England trade prices.

Figure 2-27 compares the monthly average for day-ahead LMPs with the average of the last bid and last offer for each monthly delivery period traded for ICE. Prices were similar in most months but differed by $21.75/MWh in December because of the end-of-the-year spike in day-ahead ISO electricity prices, which was not fully accounted for in the ICE bilateral market.

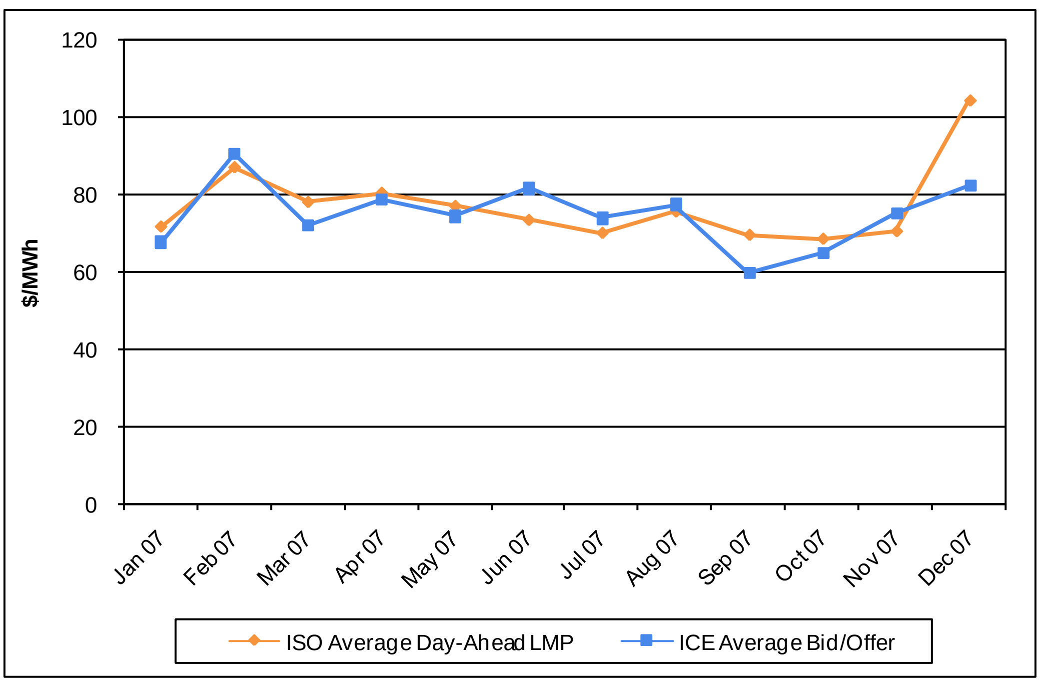


Figure 2-27: Monthly delivery—last ICE bilateral trade compared with day-ahead ISO LMPs.

2.4.6 Price Separation—Congestion and Losses

In addition to energy production costs, LMPs reflect the marginal costs of congestion and losses. The inclusion of these costs in the electric energy price and the resulting price separation between locations are key elements of efficient pricing.

Figure 2-28 shows the average hourly differences between the LMP in each zone and the LMP at the Hub in the Day-Ahead and Real-Time Energy Markets for 2007. The results for day-ahead and real-time LMPs are similar. The average LMPs for the Maine, New Hampshire, Rhode Island, SEMA, and NEMA load zones are less than the Hub LMP, and the LMPs for the Connecticut, Vermont, and WCMA load zones are greater than the Hub LMP. Differences in LMPs among the load zones are due to the joint impact of congestion and losses in the Day-Ahead and Real-Time Energy Markets. The direction and relative relationships are similar in the Day-Ahead and Real-Time Energy Markets, which indicates that the Day-Ahead Energy Market is functioning well.

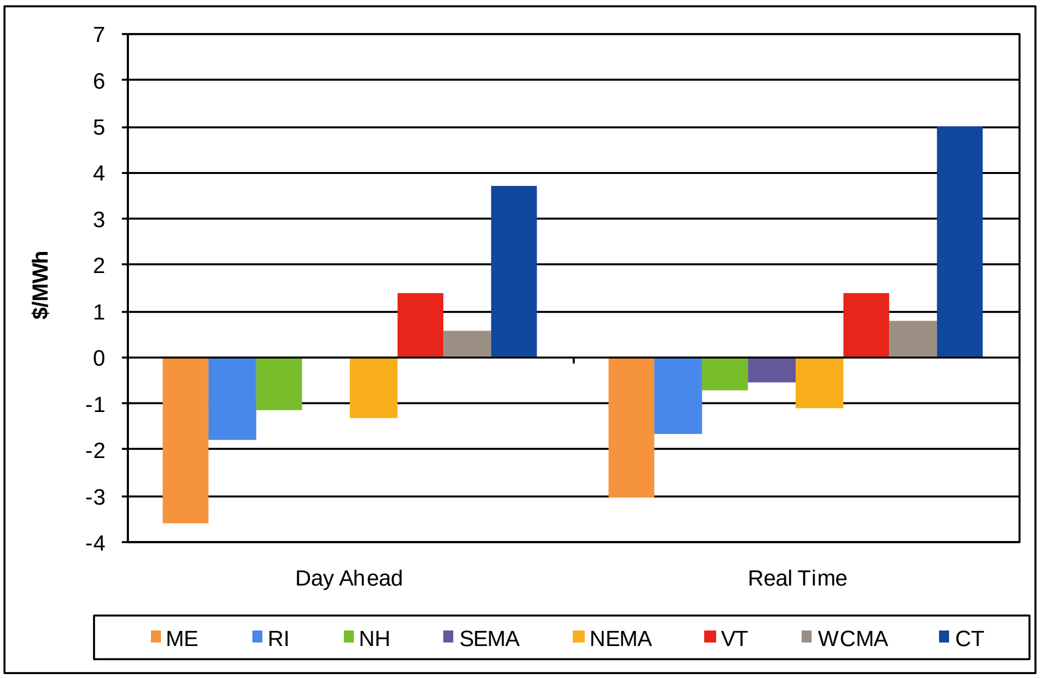


Figure 2-28: Average hourly zonal LMP differences from the Hub, 2007.

In 2007, the day-ahead price separation between Connecticut and other load zones was less pronounced than in 2006. On average in 2007, day-ahead prices in Connecticut were $3.73 higher than at the Hub, compared with $6.34/MWh higher in 2006. Real-time CT prices were higher by about the same amount as in 2006, at $5.03/MWh higher.

Total system congestion revenues from both the Day-Ahead and Real-Time Energy Markets are collected in the Congestion Revenue Fund and are used to pay FTR holders. Congestion revenues from the day-ahead market are strictly positive. Congestion revenues from the real-time market can be positive or negative. The possibility of negative congestion revenues arises because the real-time market is settled on deviations from the day-ahead market, and the deviations can be positive or negative. Deviations do not exist in the day-ahead market. Section 7 discusses the Congestion Revenue Fund in more detail.

Figure 2-29 shows total congestion revenue by quarter from the second quarter of 2003. Total congestion costs were lower in 2007 compared with 2006, dropping from $192 million to $112 million. During 2007, day-ahead congestion revenue was lower than the 2006 level, and negative real-time congestion revenue was more negative than in previous years. Both day-ahead and real-time congestion revenue combined to result in lower net congestion revenue.

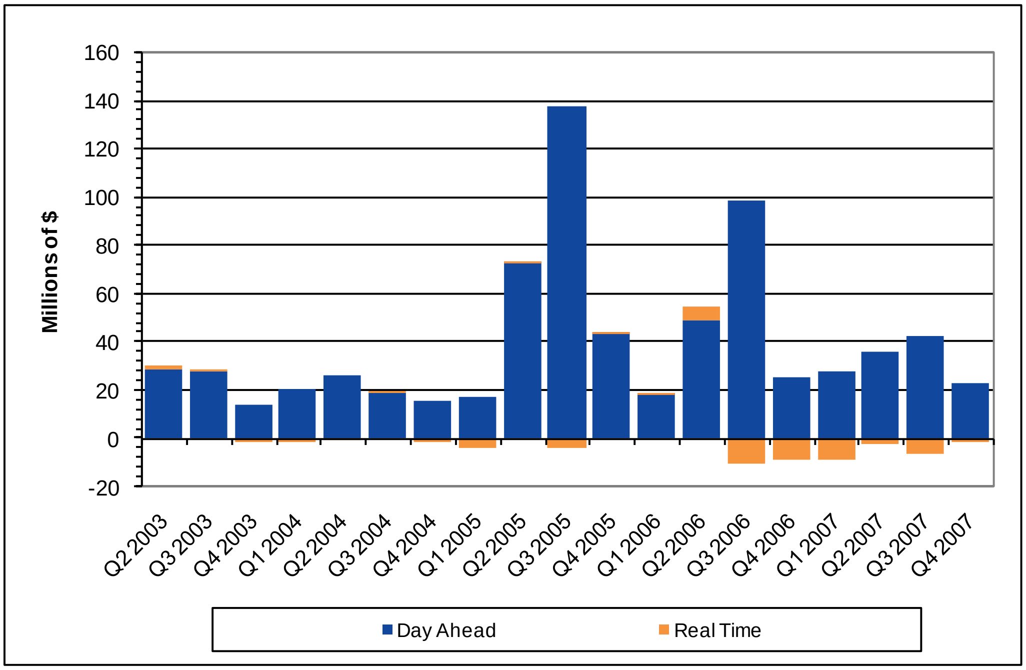


Figure 2-29: Total congestion revenue by quarter.

Table 2-7 and Table 2-8 show the 2007 averages of the congestion component, the marginal loss component, and the sum of the two components for the Hub and each load zone for the Day-Ahead and Real-Time Energy Markets, respectively. These values indicate the relative impact of congestion and marginal losses among the load zones. The proportions of the electric energy, congestion, and loss components of the LMPs are calculated in relation to a distributed reference bus. The distributed reference bus formula incorporates seasonal variations in locational load; it is not a physical interconnection to the system. Because the distributed reference bus varies over time, comparing trends in the differences between LMPs over time is more useful than comparing trends in the values of the congestion and marginal loss components. The reference bus calculation will affect the variation in each component but will not have an impact on the nodal prices.

Table 2-7
Average Day-Ahead Congestion Component, Loss Component, and Combined, $/MWh

Location/ Load Zone	Congestion Component	Marginal Loss Component	Congestion Component Plus Marginal Loss Component
Hub	–0.52	0.29	–0.23
Connecticut	2.04	1.45	3.49
Maine	–1.72	–2.14	–3.86
NEMA	–1.00	–0.57	–1.57
New Hampshire	–1.01	–0.37	–1.37
Rhode Island	–1.27	–0.77	–2.04
SEMA	0.36	–0.61	–0.25
Vermont	0.05	1.09	1.14
WCMA	–0.35	0.70	0.35

Table 2-8
Average Real-Time Congestion Component, Loss Component, and Combined, $/MWh

Location/ Load Zone	Congestion Component	Marginal Loss Component	Congestion Component Plus Marginal Loss Component
Hub	–0.92	0.19	–0.72
Connecticut	2.84	1.47	4.31
Maine	–1.53	–2.26	–3.79
NEMA	–1.22	–0.62	–1.84
New Hampshire	–1.08	–0.37	–1.45
Rhode Island	–1.48	–0.91	–2.39
SEMA	–0.58	–0.67	–1.25
Vermont	–0.35	1.01	0.67
WCMA	–0.57	0.63	0.05

Because the relative values of the three LMP components depend on the definition of the distributed reference bus, the dollar value of the congestion component should not be used directly to measure the underlying actual cost of congestion in a location over time. The differences between the LMP congestion components serve as indicators of relative congestion costs. The Hub and most load zones (ME, NH, RI, WCMA) experienced negative congestion on average in both the Real-Time and Day-Ahead Energy Markets. This means that the typical Real-Time Energy Market clearing process resulted in constraints, such that an increase in demand could have been met at a lower cost in those locations than in the other load zones. Connecticut was the only load zone with positive average congestion both in day-ahead and real-time markets. This is consistent with historical experience showing that Connecticut is a transmission-constrained area. Between 2006 and 2007, however, NEMA average congestion became negative both in day-ahead and real-time markets. The recent investment in the transmission system into Boston, which has significantly lowered congestion prices in the NEMA load zone, can explain these results.

The marginal loss component of the LMP reflects the change in the cost of transmission losses for the entire system when one additional megawatt of power is injected at that location. System losses are related to transmission voltage and the distance between generation and load. An additional injection of electricity at a location, which is estimated to decrease system losses, results in a positive marginal loss component for that location and a higher LMP. Electricity at that location has additional value because it results in smaller losses. An additional injection at a location that is estimated to increase system losses results in a negative loss component for that location, lowering the LMP. Exporting zones generally have negative loss components, while importing zones generally have positive marginal loss components. An additional injection in an exporting zone increases losses, which increases the amount of power shipped long distances. Injections into an importing zone reduce losses, which lessens the need for power to travel long distances.

Day-ahead and real-time loss components were positive in the Connecticut, Vermont, and WCMA load zones and at the Hub. They were negative in the NEMA, Rhode Island, SEMA, New Hampshire, and Maine load zones. Although the NEMA and Rhode Island importing zones had small negative losses, Maine, an exporting zone, had the most negative loss component, indicative of its long distance from the major load centers in New England. While Rhode Island and NEMA are importing zones, they are adjacent to the exporting zone of SEMA; therefore, power does not need to travel long distances to reach Rhode Island and NEMA.

Similar to congestion pricing, marginal loss pricing and accounting can result in a surplus collection of marginal loss revenue. These revenues are maintained in the Marginal Loss Revenue Fund. The revenues in the fund are allocated to load-serving entities according to each participant's monthly share of the real-time load obligation, net of bilateral trades. In 2007, a total of $93 million was returned to load-serving entities from the Marginal Loss Revenue Fund.

2.4.7 Effect of Transmission Improvements—Connecticut Subarea

The Southwest Connecticut 345 kV Transmission Project promises to improve New England transmission system reliability by allowing additional electric energy to be transferred into Southwest Connecticut to meet the regional load requirements. When the project is complete, the Southwest Connecticut import limit will increase from 2,350 MW to over 3,650 MW. Phase 1 of the project, which included transmission upgrades in the Norwalk–Plumtree area, was completed and placed in service in October 2006. Phase 2, which includes transmission upgrades in the greater Southwest Connecticut area, is 48% complete and is expected to be in service by December 2009.

The maps in Figure 2-30 show average annual real-time nodal prices for 2006 and 2007 as color gradations from blue, representing prices up to $41/MWh, to red, representing prices of $83/MWh and higher. The map shows that the chronic congestion into the southwest corner of Connecticut has been relieved.

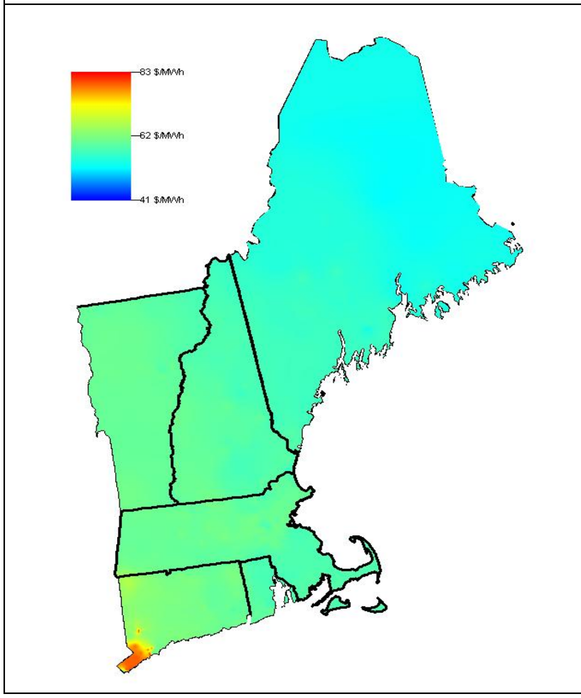
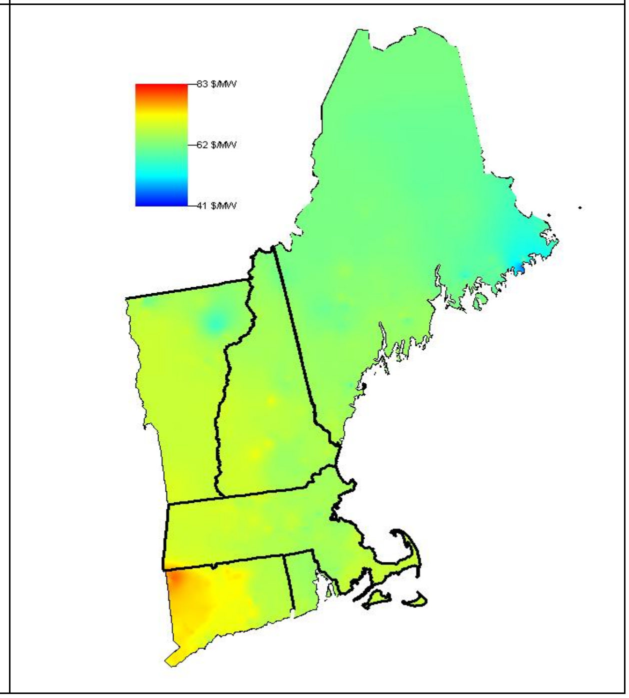
2006	**2007**
	

Figure 2-30: Average real-time nodal prices, 2006 and 2007, $/MWh.

Average nodal prices in Southwest Connecticut were affected by the elimination of the Peaking-Unit Safe-Harbor (PUSH) adder in June 2007 as well as the transmission improvements in October 2006 (see Section 6.3). Under PUSH, units with low capacity factors could offer higher prices into the market. If accepted and marginal, these offers set the price for Connecticut and raised the Connecticut price in the state above levels elsewhere in New England, which was a reflection of transmission congestion. Under the Reliability Agreements in effect since late June 2007, the same units can offer only their variable costs—the generators recover other costs through a side payment for the "annualized fixed-cost requirement." The same units still can set the marginal price for Connecticut but with no premium above marginal cost.

In addition to energy market costs, generation resources in Connecticut historically have been paid out-of-market costs associated with Reliability Agreement cost-of-service contracts and daily reliability commitments. Figure 2-31 shows the total out-of-market payments made to generators in the Connecticut load zone for daily reliability agreement payments and for second-contingency, voltage, and distribution support. Total payments to Connecticut generators outside the markets declined after the transmission improvements were put in place in October 2006. In 2007, Reliability Agreements for Devon, Wallingford, and Bridgeport Energy were terminated, while a Reliability Agreement for Norwalk Station was added. Both second-contingency daily reliability payments and net Reliability Agreement payments to resources in Connecticut decreased in 2007 compared with 2005 and 2006. (See Section 6.2 for information about daily reliability payments and Reliability Agreements.)

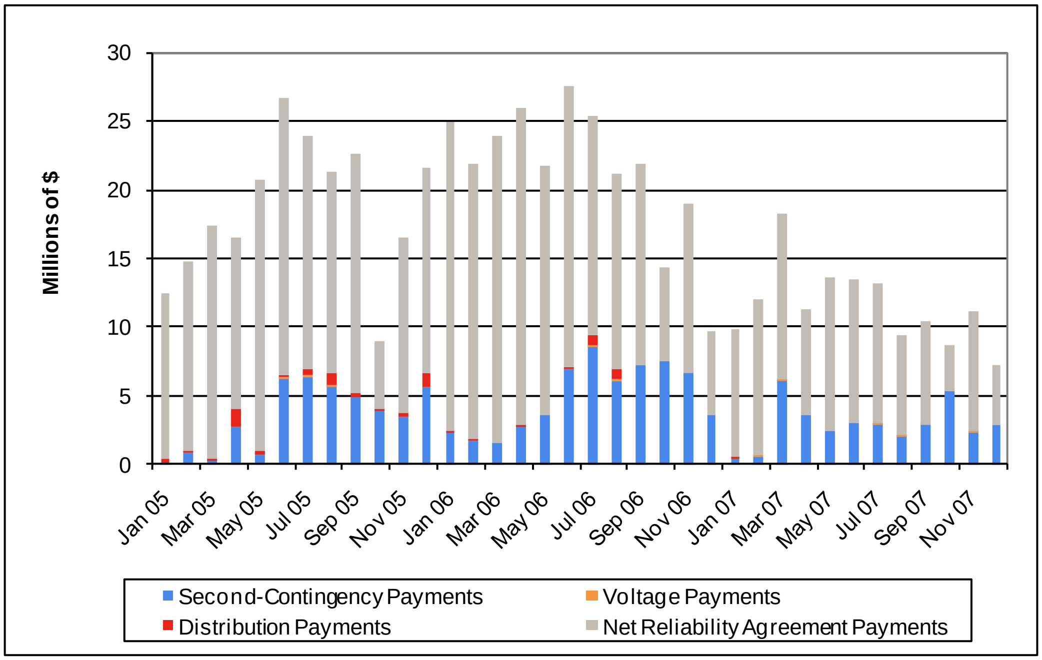


Figure 2-31: Total nonmarket payments to Connecticut generators.

2.4.8 Effect of Transmission Improvements—NEMA Boston Subarea

Transmission improvements were made in the Boston area in addition to those made in Connecticut. The NSTAR 345 kV Transmission Project improves New England reliability by increasing the Boston import limit from 3,600 MW to a range of 4,500 MW to 4,800 MW. Upgrades in the Merrimack Valley will increase system reliability for the North Shore area independent of the on-line status of Salem Harbor generation. Unlike Connecticut, the effect has not been so much on the NEMA LMP but on daily reliability payments and net Reliability Agreement fixed-cost payments. Figure 2-32 shows total daily reliability payments for second-contingency, voltage, and distribution support and total net fixed-costs payments for units with Reliability Agreements by month in the NEMA area for January 2005 to December 2007. Total annual payments declined by $85 million, but the voltage portion of the payments increased. This was driven by three changes. First, all Reliability Agreements and settlement payments to resources in NEMA were terminated as of June 2007. Second, second-contingency reliability payments decreased 31%, and third, daily reliability payments for voltage increased by approximately $40 million compared with 2006 payments. The voltage payments were similar to those in 2005 before Reliability Agreements were signed. Voltage payments increased as a result of the termination of the Reliability Agreements and their stipulated bidding.

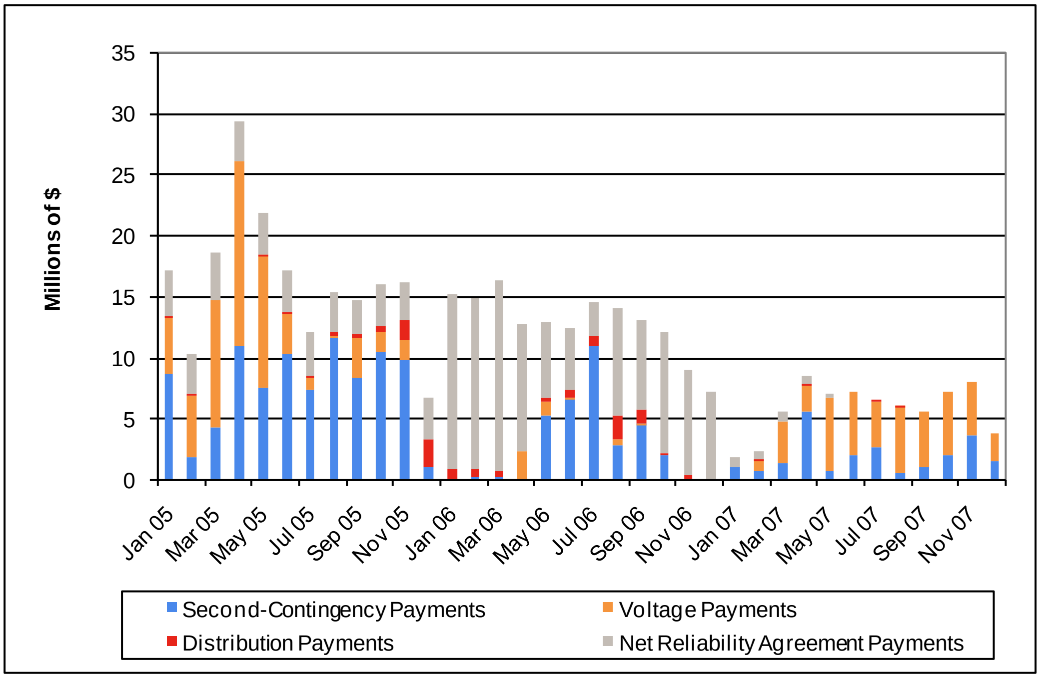


Figure 2-32: Total nonmarket payments to NEMA generators.

2.4.9 All-In Wholesale Electricity Market Cost Metric

The *all-in* wholesale electricity cost is the annual total for energy, daily reliability, capacity, and ancillary services.[58] Figure 2-33 shows the all-in wholesale electricity cost metric for New England over the past seven years ($/MWh) using a FERC-defined methodology.

[58] FERC uses this metric to compare the various regions in the country.

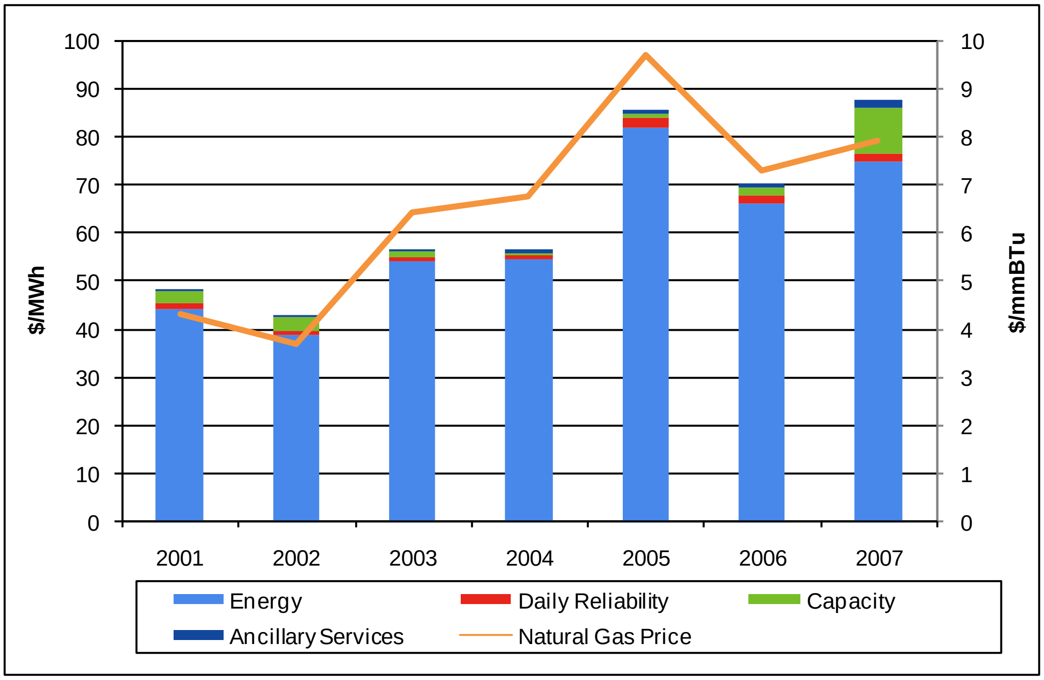


Figure 2-33: New England wholesale electricity market cost metric—electric energy, daily reliability, capacity, and ancillary services, $/MWh, and annual average natural gas prices, $/MMBtu, 2001 to 2007.

Note: Over time, the names and definitions of all-in cost components have changed. See Appendix A.4 for a description of these components for each period. Electric energy costs for the Interim Markets period = (ECP × system load). Electric energy costs for the SMD period = (real-time load obligation × real-time LMP).

Energy costs are by far the largest component of FERC's all-in wholesale cost metric, accounting for 85% of the total in 2007 down from 94% in 2006. Figure 2-33 also shows the annual average price of natural gas. The energy cost varies in a pattern consistent with the annual variations in natural gas prices, which can be attributed to New England's dependence on natural gas as a marginal input fuel. Beginning in December 2006, under the Forward Capacity Market Settlement Agreement, negotiated transition payments for capacity have been implemented.[59] With a full year of transition payments, total capacity costs rose, and as a percentage of the FERC all-in metric, capacity costs increased from 2% in 2006 to 11% in 2007.[60] Daily reliability costs and ancillary service costs combined for a total of 4% in both 2006 and 2007.

As shown in Figure 2-34, the ISO publishes a metric similar to FERC's metric presented in Figure 2-33. The ISO's market cost metric represents the average cost associated with serving real-time load obligation in the New England wholesale markets. It does not include costs that are allocated to network load, such as net payments for Reliability Agreements, ISO self-funding tariff charges, or OATT tariff charges (i.e., voltage and distribution daily reliability payments, which are allocated to transmission owners rather than participants responsible for real-time load obligation). Further, the

[59] *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. 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).

[60] The method of calculating capacity costs has changed a number of times over the period presented. See Appendix A.4.

method used to calculate components used in both metrics can differ. As an example, in the FERC metric, the energy component is calculated on the basis of real-time nodal prices, while in the wholesale load cost-report metric, the energy component is derived from real-time load-zone prices.

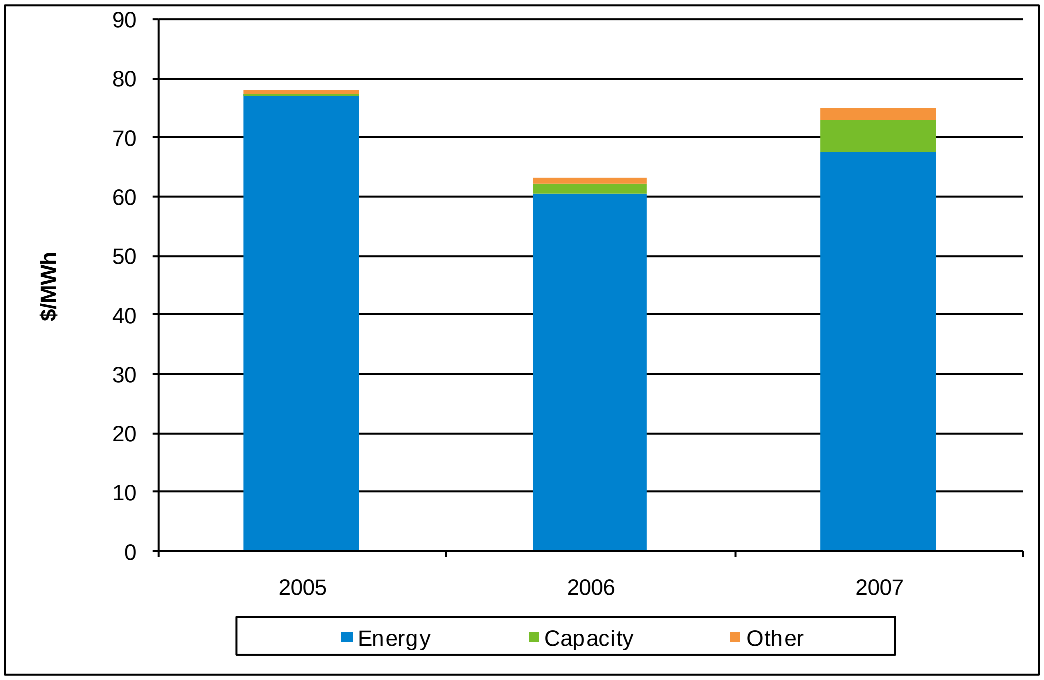


Figure 2-34: New England *Wholesale Load Cost Report* metric of all-in-costs, 2005 to 2007.

Note: The values presented are annual load-weighted averages of the monthly load zone based on data included in the ISO's *Wholesale Load Cost Reports*, which are available online at http://www.iso-ne.com/markets/mkt_anlys_rpts/whlse_load/index.html (accessed March 20, 2008).

2.5 Critical Power System Events

The high demand for electricity coincident with other events required the ISO to declare OP 4 on five days in 2007. The ISO also issued Master/Local Control Center Procedure No. 2, *Abnormal Conditions Alert* (M/LCC 2), on several occasions. The M/LCC 2 procedure alerts power system operations, maintenance, construction, and test personnel, as well as market participants, when the power system is facing a critical event or when such conditions are anticipated.[61] In 2007, the market worked as expected under these stressed conditions. This section briefly discusses the events of the days in 2007 when OP 4 actions were activated. Figure 2-35 through Figure 2-38 show real-time system conditions during OP 4 events.

2.5.1 February 10, 2007, OP 4 Systemwide

On Saturday, February 10, 2007, from 9:40 a.m. until 11:00 a.m., the ISO implemented Actions 1 and 6 of Operating Procedure 4 systemwide in New England. The actions resulted from a combination of higher-than-expected loads, lower-than-expected transfers into New England, and slightly higher-than-anticipated forced generator outages and reductions. Morning temperatures running under

[61] M/LLC 2 considers abnormal conditions to exist when the reliability of the New England Control Area is degraded. These conditions relate to forecasts of operating-reserve shortages, low transmission voltages or reactive reserves, the inability to provide some types of first-contingency protection, solar magnetic disturbances, and credible threats to the security of the power system. Additional information is available at http://www.iso-ne.com/rules_proceds/operating/mast_satllte/.

forecast by 5°F in Boston and 8°F in Hartford resulted in morning loads running 450 MW over projections. Transfers into New England were about 650 MW less than what cleared in the day-ahead market. Figure 2-35 illustrates the net capacity conditions on February 10, 2007.

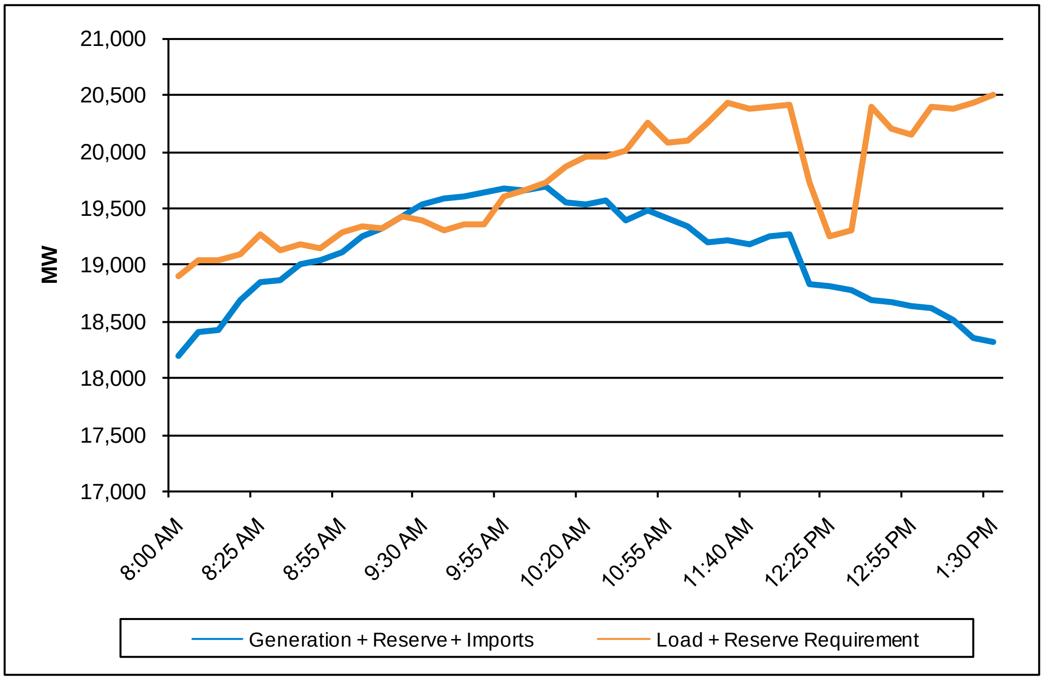


Figure 2-35: Supply and capacity required for energy and reserves, February 10, 2007, MW.

2.5.2 August 2, 2007, OP 4 Systemwide

On Thursday, August 2, 2007, OP 4 was implemented systemwide in New England as a result of higher-than-expected heat and humidity. Temperatures over the eastern portion of New England ran 6°F above forecast, and dew points throughout New England averaged 4°F above forecast. The peak-hour demand was 25,978 MW, 1,178 MW above the forecast of 24,800 MW. The ISO implemented M/LCC Procedure 2 at 2:30 p.m. At 3:30 p.m., New England went deficient in 30-minute operating reserves and implemented OP 4 Actions 1 and 6 systemwide. These OP 4 actions were cancelled at 6:00 p.m. M/LCC 2 was cancelled at 8:30 p.m. Figure 2-36 illustrates the net capacity conditions on August 2, 2007.

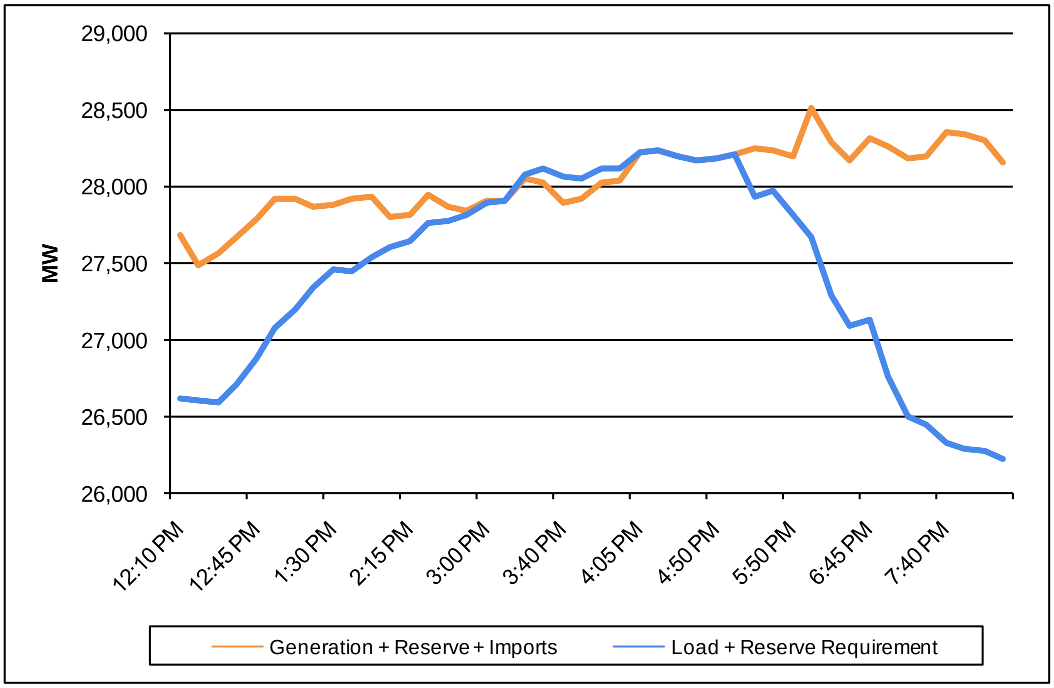


Figure 2-36: Supply and capacity required for energy and reserves, August 2, 2007, MW.

2.5.3 September 8, 2007, OP 4 Systemwide

On Saturday, September 8, 2007, OP 4 was implemented systemwide in New England as a result of higher-than-expected heat and humidity. Temperatures throughout New England ran 6°F above forecast, and dew points throughout the area averaged 2°F above forecast. The peak-hour demand was 21,876 MW for 2:00 p.m., 1,526 MW above the forecast of 20,350 MW. The ISO did not experience a 30-minute operating-reserve deficiency until 4:00 p.m., when an additional 500 MW of external sales were delivered. The ISO implemented M/LCC 2 at 12:00 noon. At 4:00 p.m., the ISO implemented OP 4 Actions 1 and 6 systemwide. M/LCC 2 and OP 4 Actions 1 and 6 were cancelled at 9:00 p.m. Figure 2-37 illustrates the net capacity conditions on September 8, 2007.

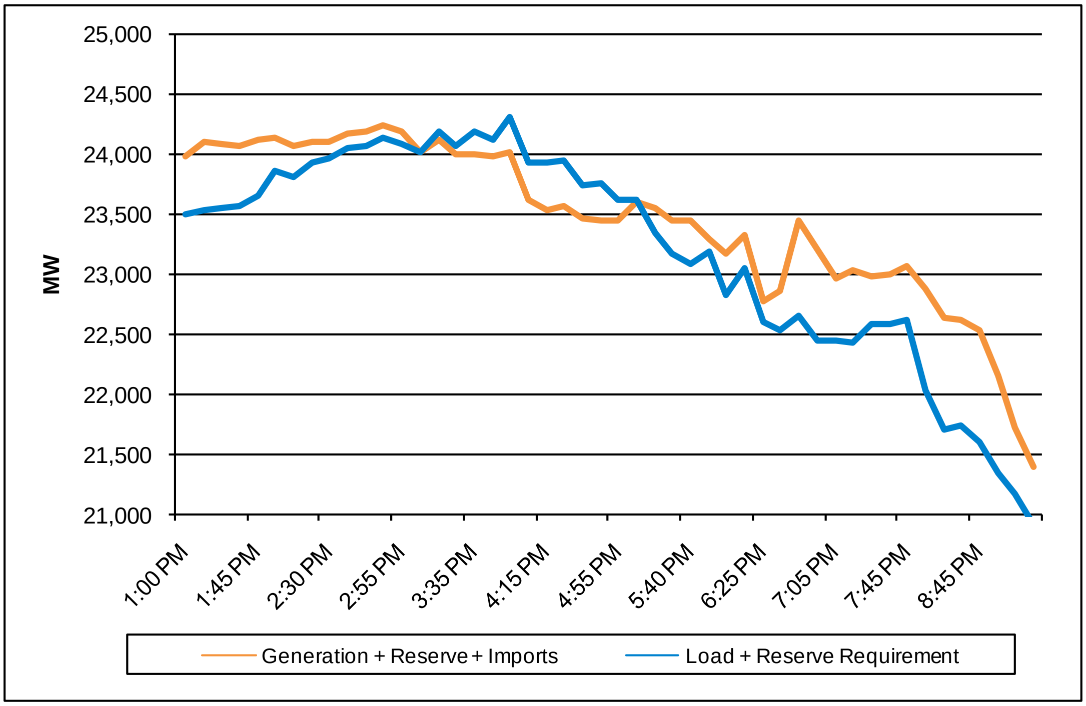


Figure 2-37: Supply and capacity required for energy and reserves, September 8, 2007, MW.

2.5.4 December 1, 2007, OP 4 Systemwide and in Maine

On Friday, November 30, 2007, the dehydration unit that separates natural gas from liquids at the Sable Island production fields, which are offshore of Nova Scotia, experienced a mechanical failure. After the failure occurred, the natural gas supply feeding the Maritimes and Northeast (M&N) pipeline was suspended. As a consequence of this event, two major natural-gas-fired generators located in Maine lost their fuel supply on Saturday, December 1, and subsequently ramped off line and out of service before the evening peak. This loss resulted in a reduction of approximately 1,000 MW of generation. In addition to the Sable Island event, two gas compressors located at Trans Canada's Lachenaie compressor station on the Trans Quebec and Maritimes pipeline (TQM) also failed on December 2.

The Sable Island dehydration unit was back in service on December 4. The M&N pipeline was fully repacked by the end of the week. The Lachenaie compressors subsequently were repaired by December 11.

2.5.4.1 Local Implementation within Maine

On Saturday, December 1, 2007, the ISO implemented OP 4 locally within the Maine area as a result of gas supply issues. M/LCC 2 was implemented in Maine at 5:00 p.m. At 6:00 p.m., OP 4 Actions 1–12 were implemented for Maine. Actions 2–12 were cancelled at 9:45 p.m. for Maine. M/LCC 2, and OP 4 Action 1 remained in effect on December 1.

2.5.4.2 Systemwide Implementation

On Saturday, December 1, 2007, the ISO implemented OP 4 systemwide in New England as a result of a combination of higher-than-forecast loads and higher-than-expected external sales and generator outages. Loads in New England ran approximately 800 MW over forecast on peak, external transactions were approximately 500 MW higher than expected, and generator outages and reductions were approximately 1,300 MW over expectations. The ISO implemented OP 4 Actions 1 and 6 systemwide at 5:45 p.m. OP 4 Actions 1 and 6 were cancelled at 8:45 p.m. Figure 2-38 illustrates the net capacity conditions on December 1, 2007.

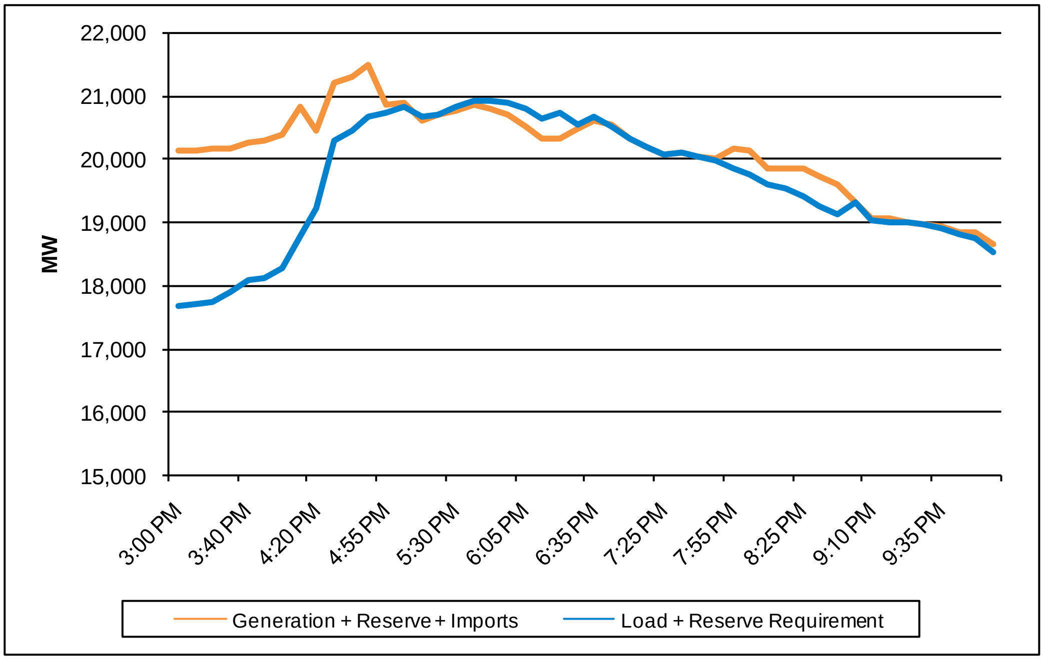


Figure 2-38: Supply and capacity required for energy and reserves, December 1, 2007, MW.

2.5.5 December 2, 2007, OP 4 in Maine

Ongoing fuel-related capacity deficiencies within the state of Maine led the ISO to remain in M/LCC 2 and OP 4 Action 1 within Maine on Sunday, December 2, 2007. At 11:00 a.m., the loss of approximately 620 MW of on-line capacity within Maine resulted in the implementation of OP 4 Actions 2–11 for Maine only. At 2:15 p.m., Action 11 was canceled, and all remaining OP 4 actions were canceled at 10:00 p.m.

2.6 Electric Energy Markets Conclusions

During 2007, electricity energy and demand levels continued to follow long-term trends. One of those trends is the continued decline of the weather-normalized load factor. Over time, this decreasing load factor will require additional generation capacity or demand response, assuming demand continues to increase.

Fuel prices continued to increase in 2007, driving energy prices higher. A notable difference during the last two years has been the increasing disparity between the price for liquid fuels and the price for natural gas. A comparison of various fuels shows that liquid fuels, such as diesel and No. 6 oil, have become increasingly more expensive than natural gas in terms of $/MMBtus. Past Annual Markets Reports have pointed out the dependence of New England on natural gas and the fact that natural gas units set the marginal price most often.[62] Recent trends, however, have increasingly pushed natural gas units toward a baseload role and generators using No. 6 oil out of this role.

Transmission investments in the Boston and Norwalk/Stamford areas have allowed more imports of electric energy into these traditional load pockets; thus, fewer Reliability Agreements are needed and daily second-contingency protection is needed less often. The results are lower congestion in Norwalk/Stamford and lower reliability payments in both areas.

[62] The Annual Markets Report archive is available online at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html.

Section 3
Forward Capacity Market

The Forward Capacity Market is a long-term wholesale market designed to promote adequate and economic investment in supply and demand resources. Capacity resources may include supply from new power plants 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 are held each year approximately three years in advance of when the capacity resources must provide service. In 2007, the significant task of qualifying all resources and potential new projects for participation in the auction was conducted. This section describes the design of the Forward Capacity Market and FCA, financial-assurance mechanisms and oversight procedures that are in place, and capacity transition payments made during the year. The section also summarizes the outcome of the qualification process and results of the first Forward Capacity Auction.

3.1 Background

In 2002, the Federal Energy Regulatory Commission charged ISO New England with developing a capacity market to address reliability issues in New England.[63] 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. 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.

3.2 Capacity Requirements

The capacity needed to satisfy the region's future load and reliability requirements is called the Installed Capacity Requirement (ICR), which is determined using specific prescribed methods and is filed with FERC before each auction. Other key FCM auction inputs that provide information on locational capacity needs are local sourcing requirements (LSRs) and maximum capacity limits (MCLs). 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. Import-constrained areas that have insufficient local capacity are assigned an LSR, and export-constrained areas that have a surplus of capacity are assigned an MCL. Areas with either an LSR or MCL are designated as *capacity zones*. Defining capacity zones helps ensure that the capacity resources procured to satisfy the ICR can effectively contribute to total system reliability. The first auction did not have any import-constrained capacity zones because each potential import-constrained area was determined to have sufficient existing capacity; Maine was modeled as an export-constrained capacity zone (3,855 MW MCL).

The design of the FCM calls for existing resources to serve a period of one capability year and new resources to serve up to five capability years. Performance incentives for delivery during the service period ensure that resources purchased through the auction will be available when needed.

[63] SMD Order. FERC Docket Nos. ER02-2330-000 and EL00-62-039 (September 20, 2002). p. 37.

3.3 Auction Design and Oversight

The capacity requirements in the geographic locations identified before each auction are used as auction assumptions to encourage development in these locations. Capacity resources compete in the annual FCA to obtain a capacity supply commitment in exchange for a market-priced capacity payment. The FCA, which is a descending clock auction, begins at a high price, with all suppliers offering (selling) the qualified capacity from each of their resources. The auction proceeds in discriminate rounds, with each round lowering the price. In each round, suppliers either can continue to offer their capacity or withdraw. The auction concludes when the capacity remaining in the auction equals the amount of resources needed (i.e., the ICR). This auction design is such that the lowest-priced new capacity that meets the region's future capacity needs will set the market price.

Many stakeholders were concerned about existing capacity resources potentially exercising market power through physical or economic withholding, or load-serving entities potentially exerting a disproportionate influence on the market by offering new supply projects at artificially low prices to depress the auction clearing price. To address these concerns, the ISO's Internal Market Monitoring Unit reviews certain bid and offer prices during the capacity qualification process.

3.4 Auction Participation Requirements

To keep barriers to entry low and increase competition, the Settlement Agreement specified that the financial assurance required from new capacity suppliers would be relatively low—a minimal level of credit enables more competitors to enter the market because they would not be required to assume a relatively large financial guaranty over the period of the project's development. However, allowing new commitments to be backed by a relatively low amount of financial security made it necessary to institute a qualification process. This process will ensure not only that any new project that clears in an auction can be interconnected, but also that the participant can back all capacity obligations with tangible assets to build the project (i.e., suppliers must demonstrate that they can provide the capacity they offered in the auction). Furthermore, 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, having each FCA procure only physical capacity resources that will be commercial and available at the beginning of each capability year is critical. For these reasons, the qualification process must be rigorous.

Although generating, demand, and import resources all may participate in the FCA to assume a capacity supply obligation, new and existing capacity resources are treated quite differently in the FCA; each type of resource has a distinctive qualification process designed to determine the correct amount of qualified capacity from each and to certify that the resource can reasonably be expected to be available during the relevant commitment period (approximately three years after the auction).

3.4.1 Existing Capacity Resources

An existing capacity resource may be an existing generating capacity resource, an existing import capacity resource, or an existing demand resource. For existing resources, the qualification process relies on a resource's current and historical demonstrated performance.

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 it can offer in the FCA during the summer portion of the commitment period). The ISO also determines each resource's winter qualified capacity for the winter portion of the commitment period (October through May).

The summer qualified capacity for an existing generating resource is set equal to the median of that resource's positive summer SCC ratings from the past five years (see Section 2.3.1).[64] The winter qualified capacity is calculated in the same manner as summer qualified capacity but based on winter SCC ratings. 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 lower capacity quantity is appropriate. All existing resources are included in the auction at their summer qualified capacity.

All existing resources automatically are entered into the capacity auction but may indicate a desire to opt out of the auction by submitting a delist bid before the existing capacity qualification deadline.[65] Delist bids indicate that the resource does not want the capacity obligation below a certain price. Bids can be static delist bids, permanent delist bids, export bids, or administrative export delist bids.

Static delist bids are bids submitted before the auction that cannot be changed during the auction. These bids may reflect either the cost of the resource or a reduction in ratings as a result of ambient air conditions.[66] The ISO may be required to submit a static delist bid on behalf of a resource if the resource's summer qualified capacity is greater than its winter qualified capacity because the resource would not be able to supply its awarded capacity during the winter period. 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 for capacity exports associated with multi-year contracts and are initiated using the same requirements as a normal export.

All delist bid submittals must include sufficient documentation for the INTMMU to determine whether the bid price is consistent with the resource's net risk-adjusted going-forward costs and opportunity costs as specified in the rules. The INTMMU reviews all delist bids that existing generators submitted at prices above specific price thresholds and new resources submitted below a specific price threshold. Static delist bids, export bids above 0.8 times the cost of new entry (CONE), and permanent delist bids above 1.25 times the CONE are subject to review by the INTMMU.[67] 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.[68]

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.

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. Resources that

[64] The qualified capacity for intermittent power resources and intermittent settlement-only resources is based on the average of the annual median net output during summer intermittent and winter intermittent reliability hours. Only four years of SCC ratings were used for the first FCA.

[65] 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.

[66] High ambient air temperatures can reduce the capacity rating of thermal generators. "Ambient air" delist bids are those made to reflect the fact that summer capability on thermal generators is less than winter capability.

[67] For the first FCA, the cost of new entry was set at $7.50/kW-month.

[68] Thresholds for delist bids requiring INTMMU review were determined in the FCM Settlement Agreement.

permanently delist are prohibited 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.

No later than 120 days before the auction, the ISO must notify participants whether their delist bids are qualified to participate in the FCA. Every delist bid submitted is binding; if it is accepted, it will be entered into the auction. Delist bids may not be withdrawn or modified after the submittal deadline. If a delist bid is not accepted (is excluded from the auction) as a result of the INTMMU's review, the ISO will explain in the notification the specific reasons for not accepting the delist bid.[69]

Unless an existing resource submits a delist bid that subsequently clears in the auction, all existing resources assume a capacity supply obligation for the relevant commitment period.

3.4.2 New Capacity Resources

A new capacity resource may be a new generating capacity resource, a new import capacity resource, or a new demand resource. Additionally, certain resources that previously were counted as capacity (including deactivated or retired resources), as well as incremental capacity from resources previously counted as capacity, may opt to be treated as a new capacity resource, subject to certain requirements.

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., Can it realistically be built and commercialized in the allotted time before the beginning of the relevant capability year?). Added to the task of reviewing new resources is the need to ensure that each new supply-side resource provides 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 also provide these services.

For demand-reduction resource proposals, the ISO ensures that the applicant's plan and methods for reducing electricity use meet industry standards. The feasibility review is the prime mechanism for assessing demand-response project criteria because these projects have no interconnection impact.

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 control area), and the import's summer and winter capability ratings. Unlike generation projects, the ISO does not evaluate the capability of new demand resources to be interconnected. However, demand resources must submit a measurement and verification plan, which outlines the project and its development and how the demand reduction is to be achieved.

[69] For rejected delist bids, the INTMMU will explain in the notification correspondence an alternate delist price and its derivation. The participant may opt to use this alternate price by informing FERC, subject to applicable market rules.

Many demand-response resources are available only during the summer. Alone, they would not be able to satisfy the year-long delivery requirement. To solve this problem, 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 the same qualification requirements for new and existing resources, 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.

Per Market Rule 1, Section 3.13.1, 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.[70] Thus, the qualification packages for these resources 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.[71]

No later than 120 days before each FCA, the ISO will notify 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. For each auction, all qualification results and auction inputs are filed with FERC. This informational filing is made approximately three months before the auction is conducted and provides interested parties the opportunity to review and comment on the ISO's fulfillment of its responsibilities before conducting the FCA.

3.5 Transition Payments

Because the first year of service does not begin until June 2010, a transition mechanism was implemented for the intervening three years. The Settlement Agreement specifies that all capacity be paid a flat rate until June 1, 2010. The transition payment rate between December 2006, the start of the payments, and December 2007 was $3.05/kW-month. The total monthly payments and capacity amounts are illustrated in Figure 3-1. Total transition payments declined during the summer because of lower ratings for seasonal claimed capability.

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

[71] The purpose of the alternative capacity price rule is to ensure that the capacity clearing price reflects the cost of new entry when new entry was prevented because of the presence of out-of-market capacity. The alternative capacity price rule sets the clearing price at the lesser 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 online at http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

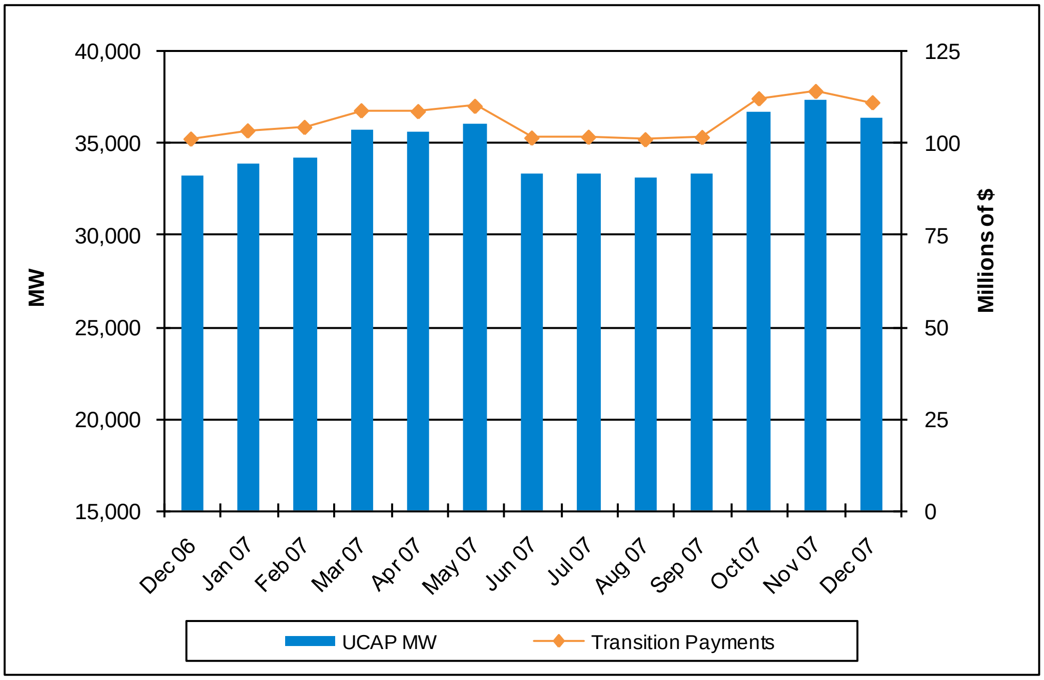


Figure 3-1: Total capacity transition payments and capacity.

Note: UCAP refers to *unforced capacity,* which is a generator's installed capacity that is adjusted for availability and is used for calculating the generator's transition payments.

3.6 Qualification Results for First FCA (2010/2011 Capability Year)

The following subsections highlight the results of the qualification process for the first FCA and include the number of projects identified as existing resources and delist bids, new capacity offers, and composite offers.

3.6.1 Existing Resources and Delist Bids

Table 3-1 summarizes the existing qualified capacity considered in the auction. These values do not include delist bids or any new capacity resources being treated as existing resources in the auction.[72] Of note is that the existing generation total includes 661 MW from three existing generating resources that have qualified as new capacity offers (repowering projects). Because the associated new capacity is mutually exclusive with the existing capacity, the total existing capacity value has been reduced to exclude these existing resources.

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

Table 3-1
Existing Capacity, MW

Capacity Type	Maine	Rest-of-Pool	Total
Generation	3,271	27,573	30,844
Imports	0	1,268	1,268
Demand response	140	801	941
Total			33,053
Repowering capacity resources			(661)
Total minus repowering resources			**32,392**

Table 3-2 summarizes the delist bids submitted for qualification and those approved for use in the auction. The deadline for submitting delists for the first FCA was April 30, 2007. Of the static delist bids, the INTMMU rejected two, and the ISO's System Planning department rejected one. The two delist bids rejected by the INTMMU had insufficient documentation supporting the delist price submitted. The one delist bid rejected by System Planning was an ambient air condition delist that lacked sufficient documentation. In addition, as provided in the market rules, the ISO submitted 21 delist bids on behalf of existing resources that had summer/winter qualification differences.

Table 3-2
Delist Bids

Type of Bid	Submitted (# Projects/MW)	Qualified (# Projects/MW)
Permanent	2 (351 MW)[(a)]	1 (1 MW)
Static	16 (227 MW)	13 (224 MW)
Export and administrative export	1 (100 MW)	1 (100 MW)
Total	19 (678 MW)	15 (325 MW)
Static—ISO submitted	21 (64 MW)	21 (64 MW)
Total	**40 (742 MW)[(b)]**	**36 (389 MW)**

(a) This total includes the New Boston Project (350 MW), which submitted a permanent delist bid. However, the resource was retired before the ISO completed its qualification review. This retired status effectively removed this resource's existing status, and therefore it will not (and cannot) be included in the auction.

(b) This total includes capacity from three existing generators that submitted repowering projects totaling 894 MW. This capacity was excluded from the existing capacity total.

3.6.2 New Capacity Offers

The deadline for submitting new capacity offers was June 15, 2007. Over 13,000 MW of new capacity was submitted by 265 different new supply projects. As shown in Table 3-3, slightly more than half of that capacity was from traditional generation projects, about 20% was from demand-response resources, and the remaining percentage was from imports. Nearly 74% of the new projects submitted, totaling nearly 20% of the new capacity, were demand-resource-type projects (traditional demand response, energy efficiency, load management, and distributed generation).

Table 3-3
New Offers Submitted

Type of Resource	Number of Projects	Capacity (MW)
Generation	62 (23.4%)	6,904 (52.9%)
Imports	8 (3.0%)	3,610 (27.7%)
Demand response[a]	195 (73.6%)	2,531 (19.4%)
Total	**265**	**13,045**

(a) A multiplier is used to derive the capacity value of and adjust the capability for demand-response resources. Unlike generating resources, demand resources reduce line losses and the need for a reserve margin. For the first FCA, this multiplier was 1.223 and was based on the peak transmission and distribution losses and reserve margin from the 2007 to 2008 Power Year.

Sixteen projects totaling 2,304 MW were disqualified. Of those, 12 were generation projects (totaling 1,658 MW), three were imports (636 MW total), and one was a demand-resource project (10 MW total). In addition, five generation projects and three import projects were withdrawn, totaling 1,488 MW and 2,316 MW, respectively. Table 3-4 summarizes the new capacity that passed qualification. The ISO reviewed these projects and deemed them capable of being constructed and interconnected by the commencement of the 2010/2011 capability year. Of the 13,045 MW of capacity submitted for qualification, 53% of the capacity from 90% of the projects submitted passed qualification. Of the qualified capacity, over one-third was demand-resource capacity.

Table 3-4
New Offers Qualified

Type of Resource	Number of Projects	Capacity (MW)
Generation	45 (18.7%)	3,758 (54.2%)
Imports	2 (0.8%)	658 (9.5%)
Demand response	194 (80.5%)	2,521 (36.3%)
Total	**241**	**6,937**

After qualification, 10 generation projects and four demand-resource projects withdrew before the financial-assurance submittal deadline, totaling 797 MW and 14 MW, respectively. Table 3-5 summarizes the new capacity offers that passed qualification and participated in the first FCA. Of significant note is that the qualified new capacity from new demand-resource projects (2,483 MW) rivaled that supplied from new generation projects (2,961 MW).

Table 3-5
New Offers Participating in the Auction

Type of Resource	Number of Projects	Capacity (MW)
Generation	35 (15.4%)	2,961 (48.5%)
Imports	2 (0.9%)	658 (10.8%)
Demand resource	190 (83.7%)	2,483 (40.7%)
Total	**227**	**6,102**

For the first FCA only, qualified new capacity projects had the option to participate in the market as existing resources (see Table 3-6). A resource owner may want to do this to guarantee that it would clear the auction. Twenty-seven percent of the qualified new capacity (1,643 MW) elected to participate as an existing resource. Of that total, 608 MW were from 18 generation projects, and 1,035 MW were from 73 demand-resource projects. The market rules specify that new real-time emergency generators (which are considered a specific type of demand-response project) are to be treated as existing resources in the auction. These emergency generators accounted for 55 of the 73 projects, or 714 MW of the 997 MW from new demand-resource projects that are being treated as existing capacity.

Table 3-6
Capacity Zone and Treatment of Qualified New Offers

Resource Type	Treated as New Capacity		Treated as Existing Capacity		Total		Total Systemwide (MW)
	Maine (MW)	Rest-of-Pool (MW)	Maine (MW)	Rest-of-Pool (MW)	Maine (MW)	Rest-of-Pool (MW)	
Generation	20	2,333	0	608	20	2,941	2,961
Imports	26	632	0	0	26	632	658
Demand resource	197	1,251	38	997	235	2,248	2,483
Total	**243**	**4,216**	**38**	**1,605**	**281**	**5,821**	**6,102**

Of the qualified capacity participating as new resources, 2,521 MW indicated an intention to remain in the auction below 0.75 times the CONE. Of that total, 1,006 MW were from 88 demand-resource projects, and 1,515 MW were from nine generation projects. Of the 97 new capacity offers reviewed by the INTMMU, seven generation projects totaling 1,185 MW failed and were treated as out-of-market in the auction. The participants representing all seven of the generation projects that failed the INTMMU review acknowledged that the offer price submitted did not reflect the long-run cost of the resource. All demand-resource projects passed the INTMMU price review.

3.6.3 Composite Offers

Table 3-7 summarizes the total capacity that could have been expected to be submitted using composite offers. Of interest is the proportion of capacity available from demand resources and imports (291 MW and 917 MW, or 24% and 75% of the total, respectively). The proportion of capacity from the rest-of-pool resources to the total available is 960 MW, or 78% of the total, and 279 MW, or 96% of all demand resources.

Table 3-7
Summer Capacity Available for Composite Offers

Capacity Zone	Demand Response (MW)	Generation (MW)	Imports (MW)	Total (MW)
Maine	12	7	246	264
Rest-of-Pool	279	10	671	960
Total	**291**	**17**	**917**	**1,224**

Table 3-8 summarizes the surplus winter capacity that could be used with summer resources to form composite offers. As expected, most of the total 3,229 MW available are from generation resources (3,123 MW, or 97%) because generation resources typically have higher winter capability ratings than summer capability ratings. Also as expected, the total winter capacity for demand resources (91 MW) is less than the summer capacity for demand resources (291 MW). Thus, the most obvious (and expected) composite combination is winter surplus generation capacity with summer-only demand-resource and import capacity.

Table 3-8
Winter Capacity Available for Composite Offers

Capacity Zone	Demand Response (MW)	Generation (MW)	Imports (MW)	Total (MW)
Maine	35	216	0	251
Rest-of-Pool	56	2,907	15	2,978
Total	**91**	**3,123**	**15**	**3,229**

Table 3-9 summarizes the composite offers submitted for the first FCA. The deadline for submitting composite offers was July 2, 2007. Seventy-three percent of the total capacity available to form composite offers was submitted and qualified (896 MW submitted compared with 1,224 MW possible). Furthermore, 82% of the demand resources for summer were captured using composite offers (238 MW were submitted out of the 291 MW possible), demonstrating that resources without year-round capacity can participate in the FCA.

Table 3-9
Submitted and Qualified Composite Offers

Capacity Zone	Demand Response (MW)	Generation (MW)	Imports (MW)	Total (MW)
Maine	4	0	26	30
Rest-of-Pool	234	0	632	866
Total	**238**	**0**	**658**	**896**

3.6.4 Informational Filing of Qualification Results to FERC

On October 2, 2007, the ISO notified FERC of the qualification determinations of all new resources, existing resources with delist bids, and composite offers. On October 11, 2007, the ISO filed with

FERC the ICR of 33,705 MW that was developed for the New England region for the 2010/2011 capability year. However, the net amount of capacity purchased in the first FCA was 32,305 MW, after deducting the 1,400 MW of Hydro-Québec's interconnection capability credits (HQICCs). On November 6, 2007, the ISO filed an informational filing with FERC summarizing all data considered in qualification and all data to be used in the auction. This submittal was approved on January 11, 2008. The November filing identified key auction inputs, including the transmission interface limits used to determine any local sourcing requirements and maximum capacity limits used to select the capacity zones modeled in the FCA.

3.7 First Forward Capacity Auction

The first FCA for the New England region for the 2010/2011 capability year was successfully concluded on February 6, 2008. The results of that auction were filed with FERC on February 27, 2008.

At the beginning of the auction, a total of 38,105 MW of capacity had been submitted (32,392 MW of existing capacity and 6,102 MW of new capacity minus 389 MW of delisted existing capacity). Compared with the ICR amount of 32,305 MW used in the auction, approximately 18% of the capacity competing in the auction was surplus.

The auction selected approximately 1,813 MW of new supply and demand resources. Of the new resources chosen, 1,188 MW represent new demand projects, and 626 MW represent new supply projects. The auction closed at the administrative floor price of $4.50/kW-month, with 2,047 MW of surplus capacity remaining. Because the auction stopped at the administrative floor price, the price received by capacity remaining in the auction at the close will be prorated. The product of the auction closing price times the ICR amount will be prorated to all remaining capacity. A more detailed examination of the auction and its results will be included in the *2008 Annual Market Report*.

3.8 Capacity Market Conclusions

The first Forward Capacity Auction was a success. The auction selected approximately 1,813 MW of new resources, including 1,188 MW of new demand projects and 626 MW of new supply projects. Notable is the breadth and depth of new capacity resources submitted for qualification. Over 13,000 MW of new capacity projects, nearly 40% of all existing capacity resources, were submitted during qualification. Of that amount, over 2,500 MW, nearly 20%, were from demand resources. Not including capacity associated with projects withdrawn by sponsors during qualification, approximately 75% of the remaining capacity successfully qualified to participate in the auction, indicating that the qualification process was fair and appropriate. Of significant note is that, of the total qualified capacity, nearly 40% was supplied by demand resources. Finally, 82% of all summer-only demand-resource capacity was able to participate using the composite-offer mechanism.

Section 4
Reserve Markets

The year 2007 was the first 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. The pricing of locational reserve needs during 2007 confirmed the importance of local reserves. This section provides an overview of the locational Forward Reserve Market and real-time reserve pricing and a summary of 2007 data for the reserve auctions, markets, and pricing levels.

4.1 Overview of Operating Reserves

Operating reserves are the unloaded capacity of generating resources that can be converted into electric energy within 10 or 30 minutes.[73] To meet the largest system contingency, ISO operating procedures require reserve capacity to be available within 10 minutes. Additional reserves must be available within 30 minutes to meet one-half of the second-largest system contingency. 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 spinning (*10-minute spinning reserve*, TMSR), while the rest of the 10-minute requirement may be nonsynchronized (*10-minute nonsynchronized reserve,* TMNSR). The entire 30-minute requirement may be served by 30-minute operating reserve (TMOR) or the higher-quality 10-minute TMSR or TMNSR. In addition to the systemwide requirements, 30-minute reserves must be available to meet the local second contingency in import-constrained areas.

The ISO reserve markets consist of forward reserve, a product similar to a capacity product, and real-time reserve pricing. The creation of a distinct capacity product for reserves was born of disappointing experience with bid-based, real-time reserve markets during the period of the Interim Markets from 1999 until 2003.[74] The Forward Reserve Market was designed to sustain long-term reserve capability with a competitive intermediate-term auction market. In line with its longer-term design, the Forward Reserve Market does not acquire spinning reserve. The real-time reserve markets, in contrast, were designed to provide co-optimization with the use of electric energy and transmission. When a resource is ramped down and redispatched for reserve rather than for energy in real-time, the real-time reserve pricing ensures that the resource’s opportunity cost is recognized in reserve prices. The redispatch also is reflected in the electric energy price.

The full implementation of the new reserve markets occurred in October 2006. At that time, the Forward Reserve Market was made locational, and real-time reserve pricing started. New England has four reserve zones: Connecticut (CT), Southwest Connecticut (SWCT), NEMA/Boston, and the rest of the system (Rest-of-System, ROS). Both the FRM and real-time reserve pricing include local TMOR requirements for CT, SWCT, and NEMA/Boston.[75] The FRM also has a TMNSR requirement

[73] Some demand-side resources also can provide reserves. See Section 8.

[74] See ISO New England’s December 31, 2001, filing in FERC Docket Nos. EL00-62-026 and EL00-62-029, and Cramton et al., *Review of the Proposed Reserve Markets in New England* (January 18, 2005), available online at http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2005/jan212005/A2_Cramton-Chao-Wilson_Review%20of%20Proposed%20Reserve%20Markets.pdf (accessed March 20, 2008).

[75] The local areas of NEMA/Boston, CT, and SWCT have no 10-minute reserve requirement. Local first-contingency recovery requirements can be met by operating at the N-1 import-interface limit.

for the system overall and a TMOR requirement for the Rest-of-System zone, while real-time reserve pricing includes both TMNSR and TMSR requirements for the entire system.

4.2 Forward Reserve Market

The Forward Reserve Market acquires capacity that can be used to fulfill off-line reserve requirements. It features twice-yearly auctions for the summer reserve period of June through September and the winter reserve period of October through May. Participants that offer into a forward-reserve auction are not required to have resources capable of providing reserves. 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. Participants must meet their forward-reserve obligation by assigning specific resources before midnight of the day before the operating day and submitting electric energy offers for those resources that exceed the strike price before the end of the reoffer period for the Real-Time Energy Market. Once a resource has been designated as a forward-reserve resource, it is obligated to be available to produce electric energy in real time when called on by the ISO.

Offers in forward-reserve auctions are capped at $14,000/MW-month.[76] Auction clearing prices are calculated separately for each reserve product in each reserve zone. When supply offers are not adequate to meet a requirement, the clearing price for that product is set to the price cap. When enough supply is offered under the price cap to meet the requirement for a product in a zone, the auction clearing price for that product is set equal to the price of the marginal supply offer.

4.2.1 Forward Reserve Market Auction Results

Two forward-reserve auctions were conducted in 2007: in April 2007 for summer 2007, and in August 2007 for the winter 2007/2008 period.

The systemwide and local reserve requirements for the locational forward-reserve auctions are shown in Table 4-1 and Table 4-2. In the summer auction, both the first and second system contingencies were assumed to be 1,400 MW. In the winter auction, the system's first contingency was higher at 1,700 MW, while the second contingency remained 1,400 MW. NEMA/Boston reserve requirements were reduced from 1,050 MW in the summer auction to 280 MW in the winter auction as a result of transmission improvements in the NEMA area that allowed additional external reserve support to meet a portion of the local-area reserve requirement.[77, 78]

[76] Market Rule 1, Section III.9.4, available online at http://www.iso-ne.com/regulatory/tariff/sect_3/.

[77] The transmission improvements resulted from the new 3164 cable (Stoughton–Hyde Park) and 3162 cable (Stoughton–K Street).

[78] External reserve support is the amount of local reserve that can be satisfied by importing reserves over transmission lines. For local second contingencies, the quantity of reserve that must be procured in the auction is equal to the contingency level minus the external reserve support level.

Table 4-1
Forward-Reserve Requirements, Summer 2007 (June 1, 2007–September 30, 2007)

Reserve Zone	Reserve Category	Contingency Type	Contingency Level (MW)	External Reserve Support (MW)	Reserve Requirement (MW)
New England Control Area	TMNSR	First	1,400	N/A	700
New England Control Area	TMOR	Second	1,400	N/A	700
Rest-of-System	TMNSR/TMOR	N/A	N/A	N/A	798
SWCT	TMOR	Local second	520	0	520
CT	TMOR	Local second	1,155	100	1,055
NEMA/Boston	TMOR	Local second	1,200	150	1,050

Table 4-2
Forward-Reserve Requirements, Winter 2007/2008 (October 1, 2007–May 31, 2008)

Reserve Zone	Reserve Category	Contingency Type	Contingency Level (MW)	External Reserve Support (MW)	Reserve Requirement (MW)
New England Control Area	TMNSR	First	1,700	N/A	850
New England Control Area	TMOR	Second	1,400	N/A	700
Rest-of-System	TMNSR/TMOR	N/A	N/A	N/A	798
SWCT	TMOR	Local second	611	0	611
CT	TMOR	Local second	1,366	0	1,366
NEMA/Boston	TMOR	Local second	1,180	900	280

The Forward Reserve Market includes a Rest-of-System requirement that ensures reserve resources are not over-concentrated in a local area. To comply with this requirement, reserves outside local reserve zones are purchased. The requirement, initially set at 600 MW and multiplied by 1.33 to account for potential failures by reserve resources, is 798 MW. The 33% accounts for failures to start by off-line fossil fuel resources, such as diesel generators and generation turbines. However, much of the ROS requirement is met by hydro resources that have a higher reliability record than comparable fast-start fossil fuel resources. In addition, the ISO's performance-capping program has ensured the accuracy of stated capabilities of the resources' reserve (see Section 4.5). Thus, the 1.33 multiplier may result in over-purchasing reserves. A revaluation of the multiplier, taking into account the mix of resources that provide reserves and the performance of these resources, might allow the ISO to lower the Rest-of-System requirement, which should lower costs.

Figure 4-1 illustrates the supply curves for the Rest-of-System TMNSR. These offers compete to satisfy the Rest-of-System TMNSR/TMOR requirement, as well as the New England-wide TMNSR requirement. These curves have not been adjusted downward for the subtraction of capacity transition payments (see Section 3). FRM payments are reduced by transition payments, which were $3,050/MW-month in 2007. Thus, an FRM offer of $3,050/MW-month would net the supplier $0 if it were the marginal offer. Appendix B includes the supply curves for the other areas and requirements.

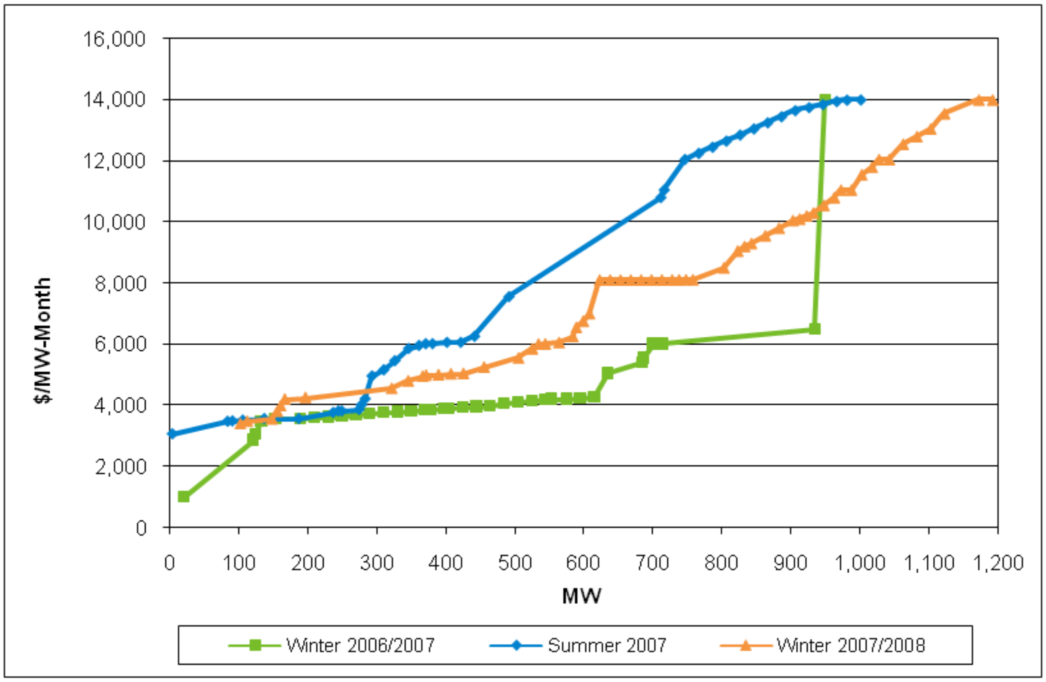


Figure 4-1: Rest-of-System TMNSR offer curves, winter 2006/2007, summer 2007, and winter 2007/2008 forward-reserve auctions.

Figure 4-1 suggests that the supply offers for Rest-of-System TMNSR from the first FRM auction under the revised market rules generally were lower than in the subsequent auctions. The offer curve increased both in size of the total amount and offer price after the first auction, suggesting that the first auction was an anomaly. The total volume of offers increased significantly in the third auction.

Table 4-3 and Table 4-4 summarize the supply conditions since the first locational FRM auction. Table 4-3 shows that requirements have been relatively stable, reflecting underlying system conditions. For example, the change in the system TMNSR requirement for winter 2007/2008 was based on a higher level of imports over the tie with Hydro-Québec. The requirements for NEMA/Boston are the exception. The requirements for NEMA/Boston dropped from 1,050 MW to 280 MW due to transmission improvements.

Table 4-3
FRM Requirements by Product

Location Name	Product Type	Winter 2006/2007 Requirement (MW)	Summer 2007 Requirement (MW)	Winter 2007/2008 Requirement (MW)
System	TMNSR	700	700	850
System	TMOR	700	700	700
ROS	TMNSR	798	798	798
SWCT	TMOR	550	520	611
CT	TMOR	1,340	1,055	1,366
NEMA/Boston	TMOR	1,200	1,050	280

Table 4-4, showing the auction surplus or shortfall at the final price, also reflects the effect of transmission improvements on NEMA/Boston. The TMOR shortfall was converted into a surplus of 160.5 MW in the winter 2007/2008 auction. The shortfall in SWCT was not stable, despite little change in requirements. This was caused by two factors. First, the CT requirement for summer 2007 was roughly 300 MW less than for either winter. The second factor was that suppliers with resources in SWCT can choose to offer in SWCT or CT. When the prices for the two areas are the same, the supplier is indifferent between the areas. Since these two prices were the same, the more appropriate comparison is the combined shortages of SWCT and CT. Each of the auction periods covered in this report experienced a shortage.

Table 4-4
Auction Surplus or Shortfall by FRM Product

Location Name	Product Type	Winter 2006/2007 Auction Surplus or Shortfall (MW)	Summer 2007 Auction Surplus or Shortfall (MW)	Winter 2007/2008 Auction Surplus or Shortfall (MW)
System	TMNSR	398.48	309.8	387.32
System	TMOR	1,959.88	1,713.2	2,330.32
ROS	TMNSR	150.48	203	394.32
SWCT	TMOR	−156	−5	−286.5
CT	TMOR	−681	−330	−416.5
NEMA/Boston	TMOR	−593	−662.2	160.5

Auction clearing results shown in Table 4-5, Table 4-6, and Table 4-7 are listed by product and location rather than reserve requirement. This is because some offers are made by location and product type. Because there are more combinations of locations and product types than market requirements, NEMA/Boston has no TMNSR requirement but does contain TMNSR supplies. The auction assigns clearing prices to each type of offer.

Table 4-5
Supply: Offered and Cleared by Reserve Zone, Winter 2006/2007

Location Name	Product Type	Offered (MW)	Cleared Supply (MW)	Clearing Price ($/MW-Month)
ROS	TMNSR	948.48	565.6	$4,200
ROS	TMOR	735.4	232.4	$4,200
SWCT	TMNSR	90	90	$14,000
SWCT	TMOR	304	304	$14,000
CT	TMOR	265	265	$14,000
NEMA/Boston	TMNSR	60	60	$14,000
NEMA/Boston	TMOR	257	257	$14,000

Table 4-6
Supply: Offered and Cleared by Reserve Zone, Summer 2007

Location Name	Product Type	Offered (MW)	Cleared Supply (MW)	Clearing Price ($/MW-Month)
ROS	TMNSR	1,001.00	691.20	$10,800
ROS	TMOR	299.40	106.80	$3,550
SWCT	TMNSR	0.00	0.00	N/A
SWCT	TMOR	515.00	515.00	$14,000
CT	TMNSR	0.00	0.00	N/A
CT	TMOR	210.00	210.00	$14,000
NEMA/Boston	TMNSR	8.80	8.80	$14,000
NEMA/Boston	TMOR	379.00	379.00	$14,000

Table 4-7
Supply: Offered and Cleared by Reserve Zone, Winter 2007/2008

Location Name	Product Type	Offered (MW)	Cleared Supply (MW)	Clearing Price ($/MW-Month)
ROS	TMNSR	1,192.32	805.00	$9,050
ROS	TMOR	448.00	0.00	N/A
SWCT	TMNSR	0.00	0.00	N/A
SWCT	TMOR	324.50	324.50	$14,000
CT	TMNSR	0.00	0.00	N/A
CT	TMOR	625.00	625.00	$14,000
NEMA/Boston	TMNSR	45.00	45.00	$14,000
NEMA/Boston	TMOR	395.50	235.00	$8,500

The results parallel the supply conditions. Supply offers in reserve zones with shortfalls (SWCT, CT, and NEMA/Boston) received the cap price of $14,000/MW-month. The change from shortfall to surplus in the NEMA/Boston winter 2007/2008 auction resulted in a price drop from $14,000/MW-month to $8,500/MW-month for TMOR. The supply of TMNSR in NEMA/Boston received the full $14,000/MW-month compared with the $9,050/MW-month for the Rest-of-System TMNSR because it was able to satisfy the system TMNSR requirement as well as the local TMOR requirement.[79]

Total quantity offered into the winter 2007/2008 auction of 3,030 MW represents an increase of 370 MW compared with the winter 2006/2007 auction. At the reserve zone level, the total quantity offered into the CT and SWCT zones increased by 44%, while the quantity offered for the NEMA/Boston area increased 39%.The price for Rest-of-System TMNSR rose significantly in the second and third auctions, suggesting that the first auction was an anomaly. This is previously discussed with Figure 4-1.

4.2.2 Bilateral Trading of Forward-Reserve Obligations

Bilateral trading of forward-reserve obligations was introduced as part of the 2006 reform. The new feature was introduced to allow suppliers facing unexpected unit outages and consequent failure-to-reserve penalties to substitute alternative resources. The feature is useful to suppliers if the cost of expected penalties for nondelivery exceeds the cost of acquiring substitute resources. The results suggest this is not the case. Penalties in the FRM market are reviewed in Section 4.6.

Figure 4-2 shows bilateral trades as a percentage of total forward-reserve megawatts. On average during the reporting period, about 24% of total auction obligations were sold through bilateral trading. However, most trades were between affiliates or other participants that had preexisting contractual relationships or were related to the sale of an asset. Less than 0.5% of megawatts traded were exchanged with the apparent objective of meeting a forward-reserve obligation that a participant would otherwise not be able to satisfy.

[79] The value of the New England-wide TMNSR constraint is calculated by the clearing engine, but it is not a stand-alone clearing price paid to a resource.

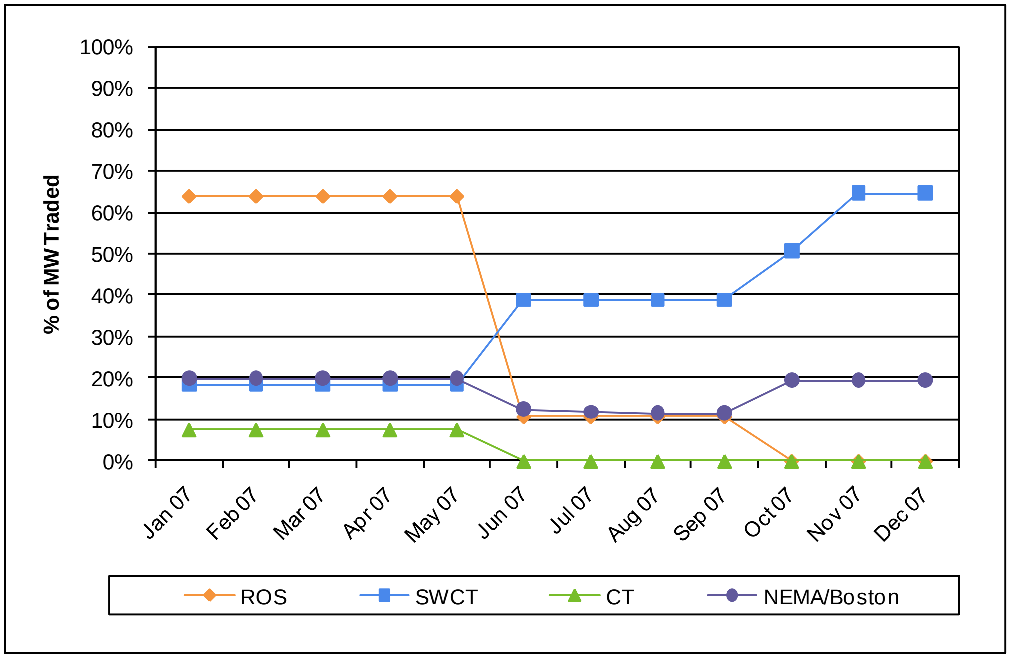


Figure 4-2: Bilateral trading of forward-reserve obligations, percentage of megawatts traded, 2007.

4.2.3 Forward-Reserve Resources

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. Resource technologies that have low capacity factors but flexible performance tend to be in the least-cost solution. These include generation turbines and hydro with storage. A measure of success of the market is the degree to which these resource types have been attracted to the market.

The results from 2007 support the hypothesis that the correct resource types have been attracted to the market. Figure 4-3 shows the total forward-reserve megawatts designated to meet forward-reserve requirements in each reserve zone during 2007 categorized by generator technology.[80] Fast-start units include reciprocating engines and combustion turbines. Non-fast-start units include fossil-fuel-fired steam plants and combined-cycle units; these units typically need to be on line to provide reserves. Hydro units that were assigned forward-reserve obligations were either pumped storage or pondage.

[80] 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.

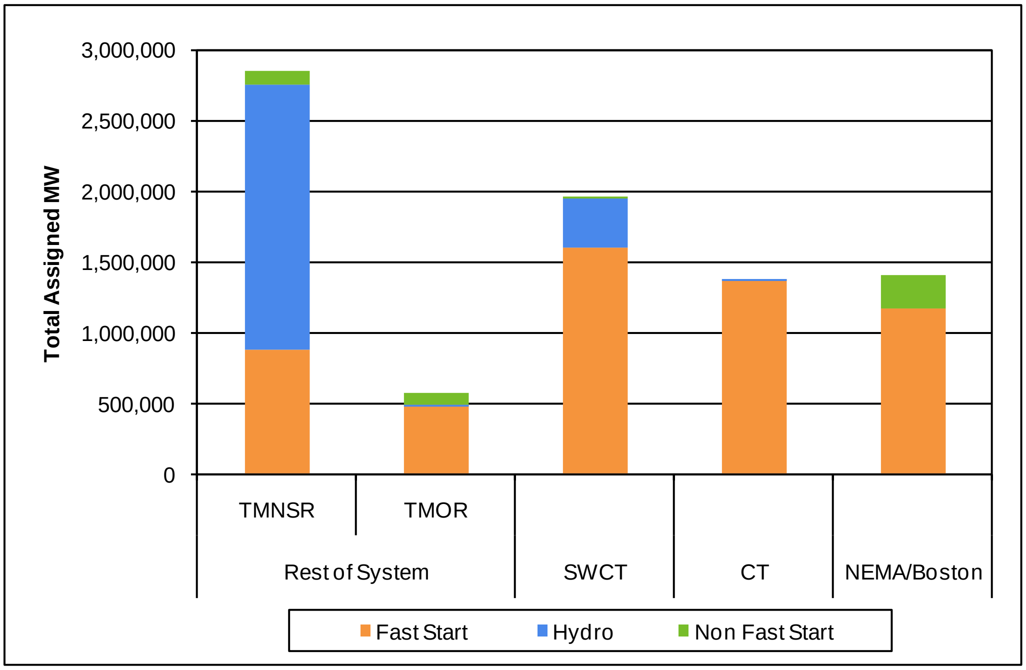


Figure 4-3: Forward-reserve-assigned resources by technology type, 2007.

4.2.4 New Generation Investment and the Forward Reserve Market

One of the goals of the reserve markets is to attract investment in generation that can respond quickly to a contingency. Analysis of participant offers into the Forward Reserve Market and new commercial generation indicates that some new capacity has been attracted to the market. The new Forward Capacity Market, with its expected revenues, plays an additional role in attracting reserve-capable capacity.

4.2.5 Forward-Reserve Threshold Price

The requirement for resources designated to meet forward-reserve obligations to offer electric energy at prices similar to those offered by low-capacity-factor resources serves to attract the long-run least-cost sources of reserve capacity that have low capacity factors. The target capacity factor is 2.5% or less. Resources designated to fulfill a forward-reserve obligation are required to offer energy at or above a threshold price that should be in merit less than 2.5% of the time. If the threshold price is set too low, some resources may take advantage of the opportunity to generate electric energy rather than provide reserves. In effect, the market could attract resources that are better suited to providing energy than providing reserve.

The formula for determining the forward-reserve threshold price is fixed for the duration of the forward-reserve service period. The forward-reserve strike price changes monthly with fuel-price indices and is calculated as a heat rate multiplied by a fuel index. The forward-reserve heat rate 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 an index for natural gas. Throughout the reporting period, the natural gas index was the lower of the two indices.

Table 4-8 shows the percentage of hours in each month with on-peak locational marginal prices that equaled or exceeded the threshold price. When the locational marginal price is higher than the calculated threshold price, a forward-reserve unit offered at the threshold price would be dispatched. If this occurs more than 2.5% of the time, resources can be dispatched more frequently than intended. This can happen for two reasons. First, a threshold price can be lower than the LMP more than the intended 2.5% of the time if the fuel index used in calculating the threshold price is lower than actual fuel prices. Second, the 2.5% 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, locational marginal prices will be higher. Table 4-8 suggests that the target of 2.5% is not being met, and the method of calculating the threshold price should be reviewed.

Table 4-8
Percentage of Hours with Real-Time LMPs Greater than or Equal to Forward Reserve Market Threshold Price, 2007

Month	Hub	CT	NEMA
Jan	8%	11%	7%
Feb	0%	1%	0%
Mar	3%	10%	3%
Apr	2%	5%	2%
May	1%	11%	1%
Jun	0%	8%	1%
Jul	1%	10%	1%
Aug	18%	28%	17%
Sep	13%	20%	15%
Oct	4%	13%	4%
Nov	1%	3%	1%
Dec	21%	23%	21%

4.3 Real-Time Reserve Pricing

In real time, resources are dispatched in the least-cost way to simultaneously meet the system's requirements for electric energy and reserves. Unlike the Forward Reserve Market, which is focused on off-line reserve requirements, real-time reserve pricing includes the systemwide spinning-reserve constraint.

Reserve pricing optimizes electric energy, local transmission, and reserve. The optimization of transmission and reserves allows the dispatch software to choose whether transmission should be used to carry electric energy or reserves when satisfying zonal reserve requirements. Reserve prices are calculated using the energy offer prices and reserve-constraint penalty factors (RCPFs) when applicable; there are no real-time reserve offers.[81] Real-time reserve clearing prices are calculated every five minutes during the operating day for each of the four reserve zones, and hourly-integrated

[81] *Reserve-constraint penalty factors* are the rates, in $/MWh, that are used within the real-time dispatch and pricing algorithm to reflect the value of operating-reserve shortages. They are defined in Market Rule 1, Section III.2.7a, available online at http://www.iso-ne.com/regulatory/tariff/sect_3/.

reserve clearing prices are calculated from the five-minute prices. The real-time reserve requirements include a system TMSR requirement, a system TMNSR requirement, a system TMOR requirement, and zonal TMOR requirements for each reserve zone. Zonal reserve requirements may be met by resources within the reserve zone and by resources outside the reserve zone through the unused import capability of the reserve zone transmission interface. Each reserve requirement constraint has a corresponding RCPF, shown in Table 4-9, that is used when the reserve requirement cannot be met.

Table 4-9
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

Reserve-constraint penalty factors are based on the amount of redispatch costs the system is willing to endure to maintain reserves, determined on the basis of the energy offer cap of $1,000/MWh. The reserve-constraint penalty factors are cumulative. For example, if both systemwide total 30-minute and 10-minute reserves are short, the dispatch software will incur costs of up to $950/MWh to maintain reserves. If electric energy prices were $1,000/MWh, the software would instruct resources as inexpensive as $50/MWh to reduce output to maintain the reserve. If electric energy prices were $950/MWh, the software would instruct resources as inexpensive as $0/MWh to reduce output to maintain the reserve.

Real-time reserve prices are expected to be zero most of the time because reserves usually are sufficient based on normal economic dispatch. At these times, no additional costs are incurred to provide reserves, and redispatching or committing resources to create reserves is not necessary. The ISO will commit and redispatch resources to provide reserves, if needed, to meet local second-contingency requirements, which will result in positive reserve prices. Market participants with resources dispatched away from their normal energy-only operating level to provide reserve may incur opportunity costs. In such cases, the marginal opportunity costs determine the reserve clearing prices.

The continuing redispatch of resources ends when opportunity costs reach the RCPF values and reserves become deficient. Therefore, RCPF values set the real-time reserve prices when reserve resources are insufficient to meet the reserve requirements, or the opportunity costs incurred by redispatching the system for reserves would be higher than the RCPF values.

When the system is redispatched to maintain reserves, the output of an inexpensive energy resource is decreased and the output of a more expensive, but slower, resource is increased. This less efficient dispatch thus is reflected in real-time electric energy LMPs. In hours when redispatch prevents a reserve shortage, the electric energy price will include a redispatch cost. This happens at the systemwide level, when systemwide reserve constraints are preserved, and at the level of local reserve zones, when local reserve constraints are involved.

The co-optimization of real-time reserve products and electric energy allows the system to provide consistent reserve prices; more valuable products always will be substituted for less valuable products when economic. This results in the more valuable product always being priced greater than less valuable products, a result often referred to as *price cascading*. The systemwide TMNSR price always will be equal to or higher than the systemwide TMOR price, and the TMSR price always will be equal to or higher than the TMNSR price. Prices also cascade among reserve locations. The SWCT TMOR price always will be equal to or higher than the CT TMOR price, and the SWCT, CT, and NEMA/Boston TMOR prices always will be equal to or higher than the Rest-of-System TMOR price.

4.3.1 External Reserve Support

Zonal reserve requirements can be met by internal resources and imported reserves, called *external reserve support* (ERS), which is unused import capability of the associated reserve zone interface. In New England's real-time co-optimized electric energy and reserve markets, the amount of internal resources providing reserves and the amount of transmission used to create ERS are optimally determined so that the electric energy and reserve requirements of the system are met at least cost.

Table 4-10 shows the ratio of ERS to the zonal reserve requirement for each reserve zone. The second column in the table shows the average ratio during all intervals. The third column shows the average ratio during the *binding reserve-constraint intervals* (i.e., intervals during which the available local TMOR plus the ERS is less than or equal to the real-time local TMOR requirement). The average ratios over binding intervals are significantly lower than the corresponding average ratios over all intervals. This is to be expected; a ratio greater than 100% indicates that unloaded interface capability is greater than the entire local requirement.

Table 4-10
Ratio of External Reserve Support to the Zonal Reserve Requirement

Reserve Zone	Average Ratio over All Intervals	Average Ratio over Binding Intervals
NEMA/Boston	185.41%	49.75%
CT	170.26%	25.45%
SWCT	168.83%	33.77%

4.3.2 Activation of Reserve Zone Transmission-Interface Transfer Limits

The reliable operation of the system requires that reserve be maintained if at all possible. Reserve may be allowed to run short if capacity is short and the system cannot be redispatched to maintain reserve. Thus, during OP 4 actions (*Action during a Capacity Deficiency*), reserve will decline below requirements. Local reserve shortages resulting from a capacity deficiency are rare. In most cases, reserve can be maintained through the process of redispatch, which normally involves decreasing the output of units with fast ramping capabilities and increasing the output of slower, more expensive units. This can incur a high cost.

The RCPF is designed to provide the desired dispatch, but it limits the redispatch cost to $50/MWh. When this redispatch cost is exceeded, operators limit the energy imports into the reserve zone by activating the reserve zone transmission-interface limit.[82] By limiting the transfer of energy into the

[82] The ISO system operating procedure, *Monitor System Security*, explains the calculation of proxy interface limits. The procedure is available online at http://www.iso-ne.com/rules_proceds/operating/sysop/rt_mkts/sop_rtmkts_0060_0020.pdf.

zone, operators can keep the remainder of the interface available for reserve (i.e., external reserve support). Inside the zone, more expensive energy units are dispatched to make up for the loss of energy imports. This is in effect a price-insensitive redispatch to maintain reserve.

The manually imposed import constraint may create a surplus of reserve and low or zero local reserve prices. Operators attempt to keep surplus reserve to a minimum so that reserve prices are not set to zero. This is not always possible, which often results in sending the wrong price signal. Frequent use of manually imposed import constraints would suggest that a higher RCPF is desirable.

Table 4-11 summarizes how often the import constraints were manually activated in 2007. The first column lists the number of days when a local reserve constraint, an import constraint, or a combination of both was kept in a binding state to maintain local reserve. The second column lists the number of days a local reserve constraint was used. The third column lists the number of days operators activated the reserve zone transmission-interface limit. The last two columns calculate the percentage of reserve event days that either the reserve constraint or the import constraint was used. As discussed, the operators attempt to keep the reserve constraint in a binding state when the import limit is activated. Therefore, the events overlap, and the percentages calculated by last two columns sum to more than 100%.

Table 4-11
Local Reserve Constraints and Manual Activation of Interface Transfer Limits, 2007

Reserve Zone	Reserve Event Days	Days Reserve Constraint Used	Days Interface Limit Activated	Percent Reserve Constraint Used	Percent Import Limit Activated
NEMA/Boston	7	4	4	57.1%	57.1%
CT	28	25	15	89.3%	53.6%
SWCT	23	21	8	91.3%	34.8%

NEMA had a total of seven days in 2007 with reserve events that had a binding reserve constraint, an import limit activated to maintain reserve, or a combination of both. The reserve constraint was binding in four of those days, and a manually imposed import constraint also was imposed during four of the seven reserve event days. The import limit and reserve constraint both were activated during 57.1% of the reserve event days.

The Connecticut reserve zone used manual import constraints on 15 out of a total possible 28 days (53.6% of the time). The Southwest Connecticut reserve zone used manual import constraints on eight out of a total possible 23 days (34.8% of the time). Overall, the current RCPF of $50/MWh is sufficient a majority of the time. However, the results suggest that the number of manual interventions could be reduced significantly with a higher RCPF for local reserve.

4.3.3 Real-Time Reserve Clearing Prices

Higher-quality reserves always may substitute for lower-quality reserves. Thus, 10-minute spinning reserves may substitute for 10-minute nonsynchronized reserves, which the prices reflect. The reverse is not true; 10-minute nonsynchronized reserves cannot substitute for 10-minute spinning reserves. For example, at the system level, when the 10-minute nonspinning reserve requirement is binding, the 10-minute spinning reserve clearing price will be at least equal to that of the TMNSR. The process is the same for 30-minute operating reserves, systemwide and locally. Thus, a resource in SWCT, nested within the Connecticut reserve zones, can provide relief to either SWCT or to the rest of CT.

The price for SWCT reserve reflects this higher value and is at least as great as the price for reserve in CT. Both prices will be at least that of the ROS price.

Positive reserve-clearing prices occurred in at least one zone in 452 hours during 2007. Figure 4-4 shows the frequency of hours with positive real-time reserve clearing prices in 2007. Positive reserve-clearing prices occurred most frequently in the SWCT reserve zone, where prices for local TMSR were positive in 5.1% of hours. In the Rest-of-System reserve zone, TMSR prices were positive in 3.3% of hours.

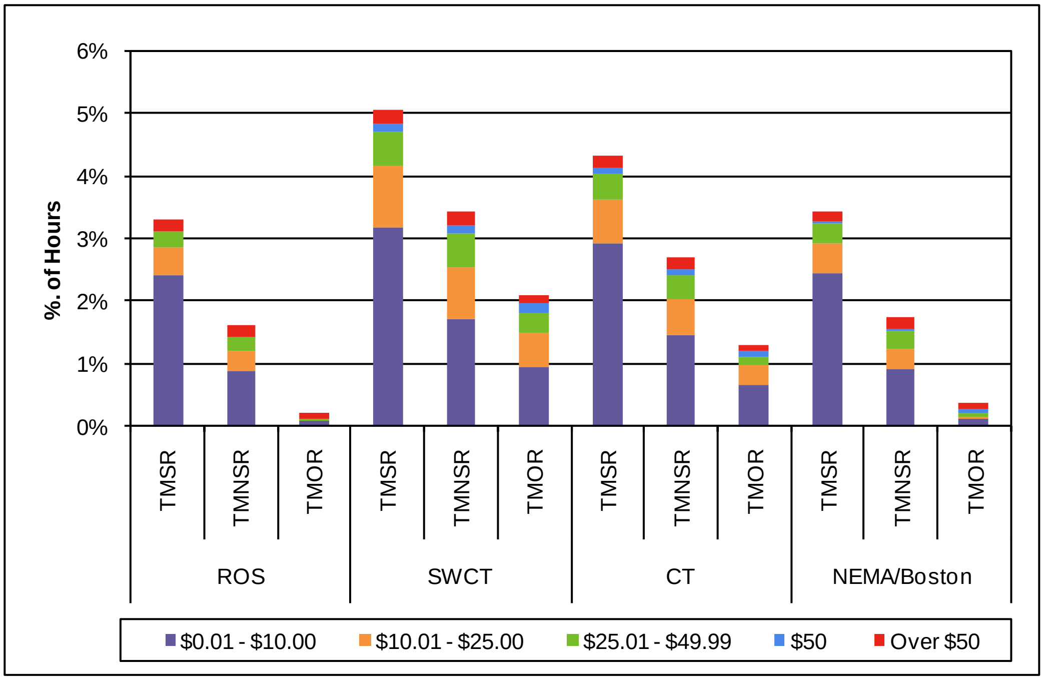


Figure 4-4: Real-time reserve clearing-price frequency in each reserve zone, 2007.

4.4 Real-Time Reserve Shadow Prices

Reserve shadow prices are the shadow prices of the reserve constraints in the market system dispatch algorithm, representing the cost to the system of redispatching units to maintain local reserve. Because shadow prices correspond directly to particular reserve requirements, the prices are not cumulative with lower-quality reserve prices and thus present a more detailed picture of actual real-time reserve conditions. While Figure 4-4 shows that positive SWCT TMOR clearing prices occurred in about 2% of hours, Figure 4-5 shows that the redispatch for local SWCT TMOR was responsible for only about half of these, or just over 1% of hours, while CT and ROS TMOR accounted for the rest. Positive shadow prices occurred most frequently for Rest-of-System TMSR. During 2007, the Rest-of-System TMSR constraint was binding in 1.6% of hours.

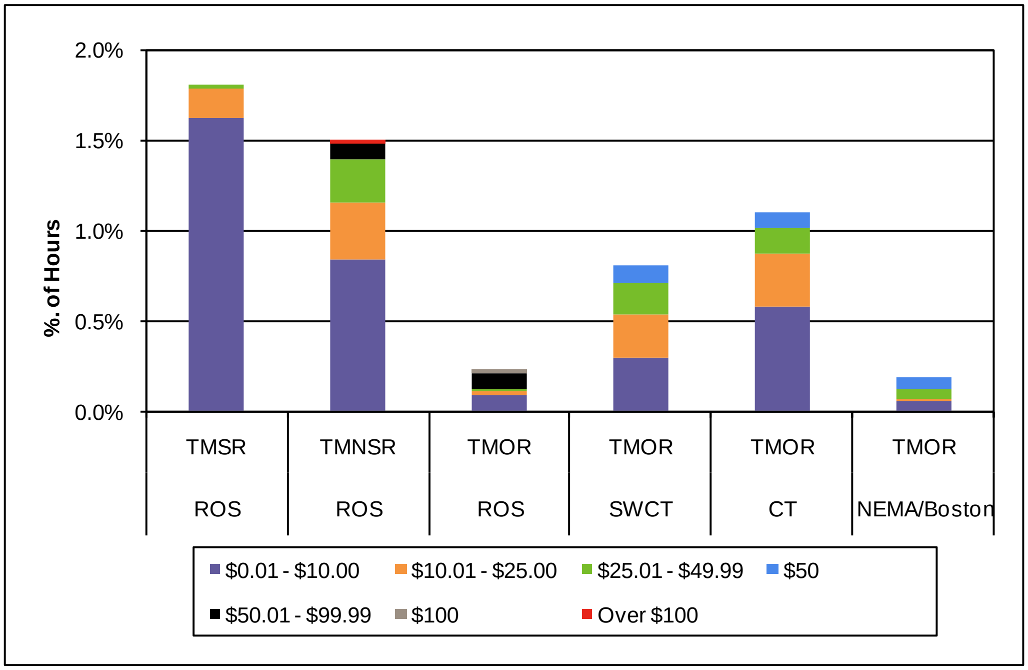


Figure 4-5: Real-time reserve shadow-price frequency, 2007.

4.5 Performance of Reserve Resources

In conjunction with the revised reserve markets, additional performance monitoring and auditing for resources with claimed reserve capability was implemented. Beginning in January 2007, failure to perform, either during normal operations or during audits, results in capping the megawatt value of reserve credit allowed to the nonperforming resource. The ISO evaluates the performance of every start of a fast-start generator that claims to have 10- or 30-minute off-line reserve capability, and generators' claimed 10-minute and claimed 30-minute reserve values are capped at the megawatt value produced.

The imposition of a performance cap does not incur an immediate financial penalty. Rather, it reduces the capability to get paid for real-time reserves or forward reserves. The repercussions for a seller of forward reserves can be more severe than for real-time reserves. If the seller has no alternative resource to fulfill a forward-reserve obligation, the seller must pay an alternative supplier to take on the obligation or pay a failure-to-reserve penalty. This is in addition to not receiving the forward-reserve payment.

The performance auditing and capping program has improved the measurement of reserve capability. Figure 4-6 shows the impact of performance capping on total system 10-minute and claimed 30-minute reserve capability. The result is that the generators that retained their fast-start designations (i.e., those with verified off-line 10-minute and 30-minute reserve capability) start up and perform reliably. This ensures that only resources truly capable of providing reserves from an off-line state can participate in the reserve markets. Many of the generators that were eliminated from the pool of fast-start generators were run-of-river hydropower facilities, typically nondispatchable and thus not eligible to provide reserves.

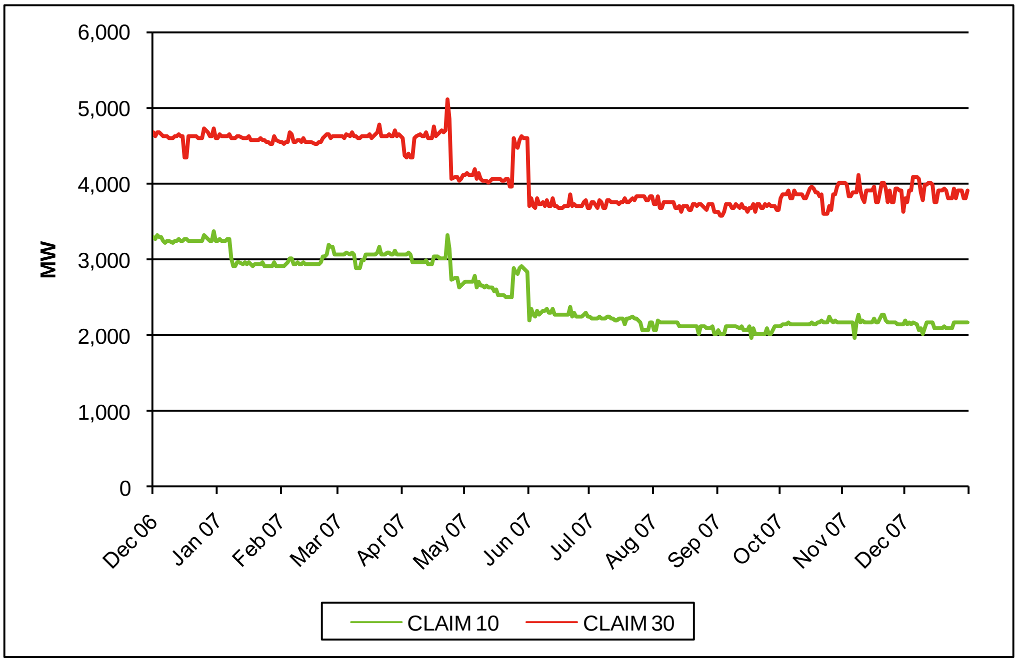


Figure 4-6: Daily average hourly total claimed 10-minute and claimed 30-minute reserve, 2007.

4.6 Reserve Payment Settlement Results

The forward-reserve auction clearing price is converted into an hourly payment rate based on on-peak hours.[83] Generators assigned daily forward-reserve obligations are paid this hourly price. Payments are reduced by any failure-to-reserve or failure-to-activate penalties. Penalties are assessed if a participant does not offer an available, forward-reserve-capable resource into the electric energy market at or above the threshold price, or if an assigned resource is not able to provide energy within 10 or 30 minutes if called on during real-time operations.[84]

Resources assigned to meet forward-reserve obligations are sometimes designated as reserve resources in real time.[85] When real-time reserve payments are positive and a resource that has been assigned for forward reserve also is designated for real-time reserve, double payment is avoided by subtracting the appropriate amount of real-time reserve credit. These adjustments, referred to as *forward-reserve energy obligation charges*, were $1.6 million in 2007.

Table 4-12 shows forward and real-time reserve payments and penalties by month for 2007. The net forward credit is equal to forward-reserve payments minus penalties and forward-reserve energy obligation charges. Net payments for forward reserves were approximately $164 million in 2007. Failure-to-reserve penalties in 2007 totaled $6.4 million, and a failure-to-activate penalty of $3,537 was paid in August 2007. Payments to resources that provided real-time reserves totaled

[83] The auction clearing price is adjusted to reflect payments made in the Forward Capacity Market before being converted to an hourly rate.

[84] Participants receive exceptions to the failure-to-reserve penalty for periods when the unavailability is due to scheduled annual maintenance. Failure-to-activate penalties are applied only when control room operators have approved a contingency unit-dispatch software case.

[85] Real-time reserve pricing is possible in all hours; forward-reserve obligations are for weekday on-peak hours only.

$6.57 million in 2007. Table 4-13 shows yearly total net forward-reserve and real-time reserve payments by reserve zone.

Table 4-12
Payments and Penalties to Reserve Resources, by Month, 2007

Month	Net Forward Credit	Forward Credit	Fail-to-Activate Penalty	Fail-to Reserve-Penalty	Forward-Reserve Obligation Charge	Real-Time Credit
Jan	$11,006,076	$11,376,627	$0	-$344,774	−$25,777	$446,794
Feb	$11,149,985	$11,422,604	$0	-$272,618	$0	$132,290
Mar	$10,880,064	$11,239,023	$0	-$323,368	−$35,590	$150,482
Apr	$10,897,715	$11,301,365	$0	-$149,416	−$254,234	$561,811
May	$10,236,788	$11,045,356	$0	-$382,267	−$426,301	$809,353
Jun	$16,281,110	$17,086,596	$0	-$741,257	−$64,229	$73,903
Jul	$16,128,171	$17,019,508	$0	-$865,962	−$25,375	$26,248
Aug	$16,052,937	$17,098,091	-$3,537	-$741,533	−$300,084	$415,201
Sep	$16,108,135	$16,797,160	$0	-$450,175	−$238,849	$1,172,557
Oct	$14,128,372	$15,097,741	$0	-$874,174	−$95,195	$318,199
Nov	$15,081,668	$15,859,972	$0	-$713,438	−$64,866	$725,737
Dec	$15,857,671	$16,549,862	$0	-$542,222	−$149,968	$1,736,138
Total	**$163,808,694**	**$171,893,905**	**−$3,537**	**−$6,401,204**	**−$1,680,469**	**$6,568,714**

Table 4-13
Payments to Reserve Resources, by Reserve Zone, 2007

Reserve Zone	Net Forward Credit	Real-Time Credit
Rest-of-System	$36,599,954	$3,436,396
SWCT Reserve Zone	$50,593,675	$1,350,157
CT Reserve Zone	$41,598,461	$997,684
NEMA/Boston Reserve Zone	$35,016,605	$784,477

The value of penalties is 3.73% of the forward-reserve credit. As previously noted, the forward-reserve bilateral market is very limited, which suggests that the penalties are too small to motivate use of the bilateral market. However, the resources designated in the Forward Reserve Market include a large amount of hydro, suggesting that the market correctly values high-performance resources.

The cost of paying resources to provide reserve is allocated to market participants based on real-time load obligations.[86] Load-obligation quantities in load zones are price-weighted by the relative forward-reserve clearing prices of the reserve zones that correspond to each load zone, and charges are based on these price-weighted load obligations.[87] Table 4-14 shows total reserve charges for the reporting period, while Table 4-15 shows average hourly reserve charge rates. Forward-reserve charges are for on-peak hours only, while real-time reserve charges are for all hours. The SWCT reserve zone does not have a separate allocation.

Table 4-14
Total Reserve Charges to Load, by Load Zone, 2007

Market	Product	CT Load Zone	NEMA Load Zone	Rest-of-System
Forward reserves	TMNSR	$14,097,970	$11,060,669	$17,938,392
Forward reserves	TMOR	$58,951,263	$39,626,835	$22,133,565
Real-time reserves	TMNSR	$854,541	$371,461	$932,985
Real-time reserves	TMOR	$1,025,696	$142,518	$187,818
Real-time reserves	TMSR	$856,976	$597,832	$1,598,887

Table 4-15
Average Hourly Reserve Charges to Load, by Load Zone, $/MWh, 2007

Market	Product	CT Load Zone	NEMA Load Zone	Rest-of-System
Forward reserves	TMNSR	$0.7979	$0.7979	$0.4676
Forward reserves	TMOR	$3.3597	$2.8597	$0.5782
Real-time reserves	TMNSR	$0.0234	$0.0121	$0.0111
Real-time reserves	TMOR	$0.0266	$0.0038	$0.0019
Real-time reserves	TMSR	$0.0231	$0.0203	$0.0195

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

[87] Payments to resources providing reserves are based on reserve zone prices, while charges are allocated to load-serving entities based on load zones. 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.

4.7 Reserve Market Conclusions

Overall, participation in the FRM auctions has increased across the three auctions that have been held since a locational component was added to the FRM in October 2006. Transmission improvements in the NEMA/Boston reserve zone lowered the reserve requirement for that zone in the winter 2007/2008 forward-reserve auction, and NEMA/Boston TMOR cleared below the auction price cap for the first time. Forward-reserve requirements for the SWCT and CT reserve zones were not met in any of the three auctions. The persistent shortage due to insufficient offers in SWCT and CT represents an issue that needs further evaluation.

Additional opportunities exist to incrementally improve the Forward Reserve Market. The forward-reserve threshold prices are lower than LMPs more frequently than envisioned in the market design. This suggests that the method for setting them should be reexamined.

The performance-capping program has enabled accurate measurement of off-line capability and thus has improved the reserve markets' performance and reliability. These improvements, combined with the selection of the hydro resources for Rest-of-System reserve, suggest that the FRM Rest-of-System purchase requirement should be reevaluated to reduce costs.

Positive reserve-clearing prices occurred in at least one zone in 452 hours during 2007. Positive reserve-clearing prices occurred most frequently in the SWCT reserve zone, where prices for local TMSR were positive in 5.1% of hours. In the Rest-of-System reserve zone, TMSR prices were positive in 3.3% of hours. These results are in line with expectations for the reserve market. However, at times, the redispatch was not sufficient to create reserves, and operators had to bind the import limit manually in Connecticut. The ISO is evaluating the causes for activating the import limit more frequently than expected.

Section 5
Regulation Market

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. 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.[88] This system balancing also maintains proper power flows into and out of the New England Control Area. The Regulation Market is the mechanism for selecting and paying generation needed to manage this system balancing.

On October 1, 2005, the ISO implemented modifications to the Regulation Market.[89] The market changes included adding a service payment and improving the calculation of opportunity costs. The Regulation Market clearing price 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 (RCP) as was done in the Regulation Market before October 1, 2005.

The Regulation Market performed effectively in 2007. Total costs fell relative to 2006 when participants were still gaining experience with the revised market implemented in late 2005. This section discusses the performance of the Regulation Market in 2007. It also summarizes the results and a cost analysis for 2007 and reforms made to the offer-selection software.

5.1 Regulation Performance

The primary objective of the Regulation Market is to provide the necessary resources and market-based compensation to allow the ISO to meet NERC's *Real Power Balancing Control Performance Standard* (BAL-001-0) for control areas (NERC balancing authorities).[90] The primary measure used for evaluating control performance is Control Performance Standard 2 (CPS 2), which is as follows:[91]

> *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}.*[92]

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[88] 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).

[89] The ISO's 2003 through 2005 *Annual Markets Reports* contain details on the SMD Regulation Market. These documents are available online in the ISO archive at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html.

[90] This standard (effective April 1, 2005) can be accessed online at http://www.nerc.com/~filez/standards/Reliability_Standards.html#Resource_and_Demand_Balancing.

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

[92] The *area control error* of the New England Control Area is the actual net interchange minus the biased scheduled net interchange.

For the New England Control Area, the CPS 2 annual average compliance target is 92% to 97%. Figure 5-1 shows the CPS 2 compliance for each month in 2007 and the 90% lower monthly limit. The ISO has continually met its CPS 2 targets.

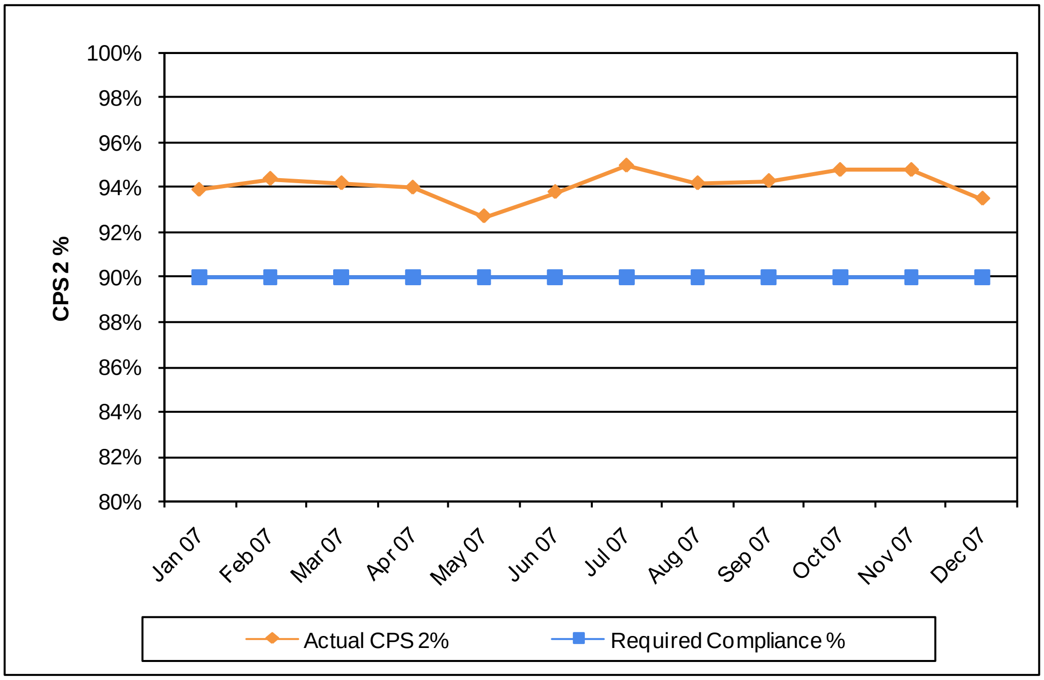

Figure 5-1: CPS 2 compliance, 2007.

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.[93] Figure 5-2 shows a time-weighted monthly average of the regulation requirements. In the figure, the requirements for June 2001 through February 2003 have been converted from REGS (the regulation requirement of the Interim Market) to megawatts of regulation to be consistent with present market requirements. Figure 5-2 shows a gradual downward trend of the average monthly requirements over the period. The ISO has been able to reduce the requirements, in part, because the response of the regulation resources to the regulation-control signals has improved overall. Regulation requirements are lower during spring and fall than in summer and winter.

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

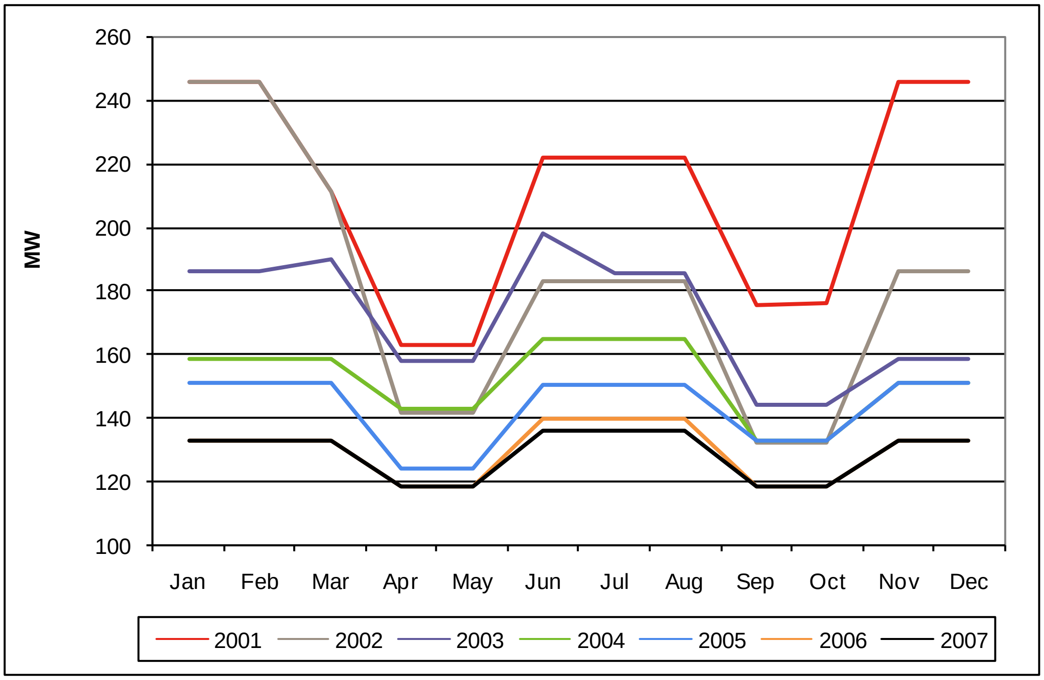

Figure 5-2: Monthly average regulation requirements.

Note: Requirements shown in the plot for January 2001 to February 2003 were converted from REGS to megawatts for consistency.

New England has approximately 2,358 MW of installed regulation capacity. The pool of resources available for regulation on an hourly basis is a subset of all regulation-capable generators that submit an offer for regulation; are on line, are producing energy, and are dispatchable; and have appropriate real-time parameters. In general, about 6%, or just over 130 MW, of the installed regulation capability is available to provide regulation in a given hour.

5.2 Regulation Market Results

Payments to generators for providing regulation totaled $43.8 million, including $14.7 million in service credit payments, $14.1 million in real-time opportunity cost payments, and $15.0 million in regulation capacity credits. During 2006, total payments to generators for providing regulation were $78.1 million. Figure 5-3 shows total regulation payments by month from January 2005 through December 2007. Costs increased after the implementation of the market modifications in October 2005. In early 2006, shifts in supply, combined with a reduction in fuel costs, led to a substantial reduction in Regulation Market costs. Total monthly costs for regulation returned to levels experienced before the market modifications in 2005.

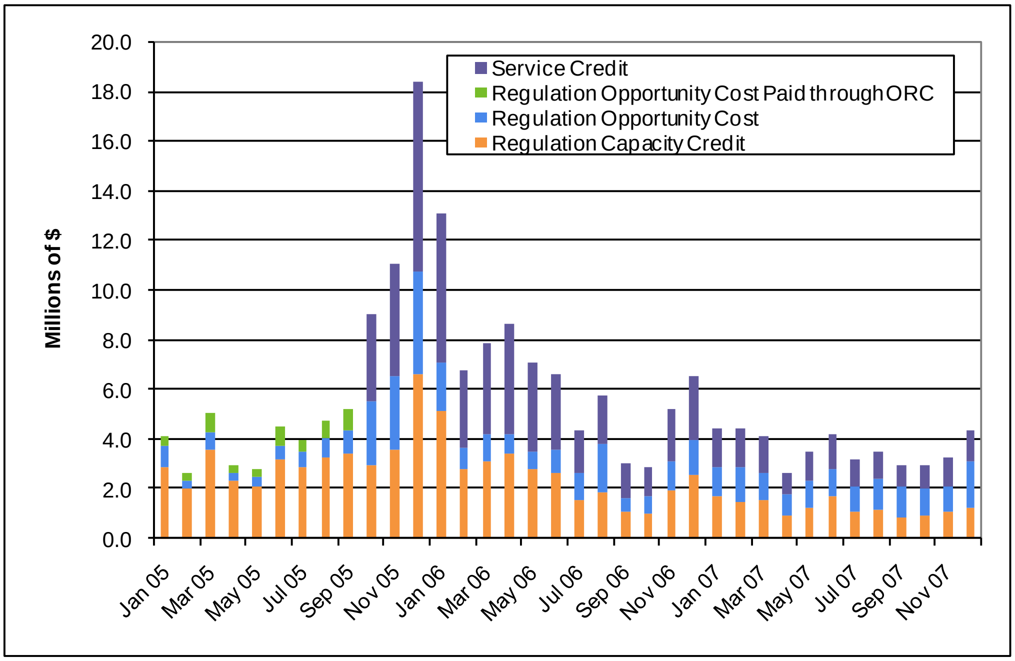

Figure 5-3: Total regulation payments by month.

Note: *Operating reserve credit* (ORC) refers to the out-of-market compensation mechanism used before October 2005. The compensation payments in the current market design are daily reliability payments.

As Figure 5-4 illustrates, average 2007 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.

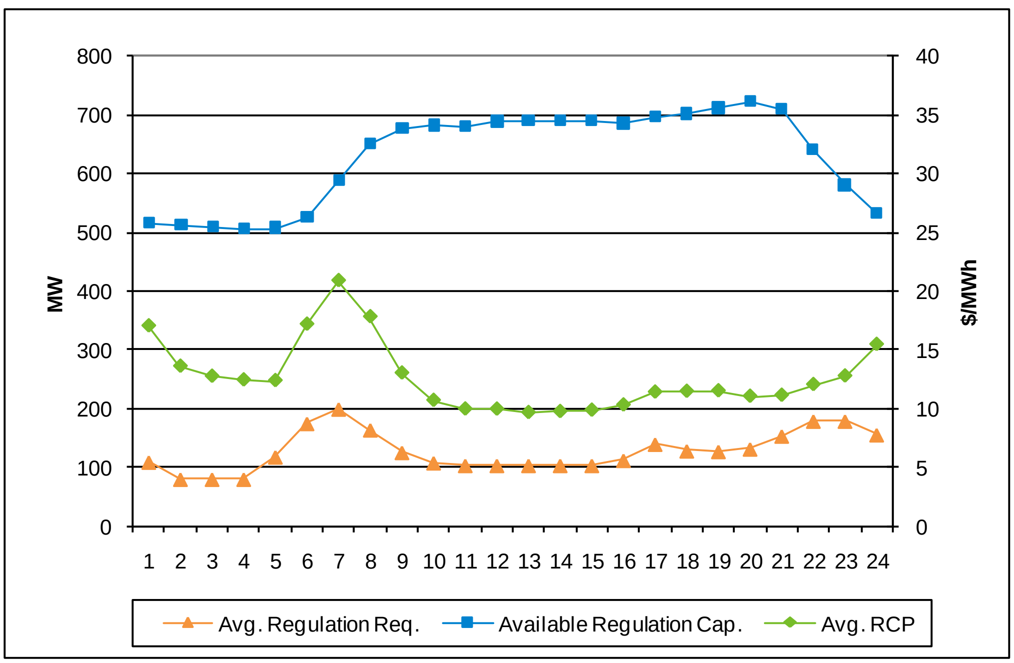

Figure 5-4: Average regulation requirements, available regulation capacity, and average hourly regulation clearing prices, 2007.

5.3 Regulation Market Analysis

Monthly Regulation Market costs increased substantially in late 2005 and continued into early 2006 following the implementation of the new design as part of Ancillary Services Market (ASM) I project in October of 2005.[94] Table 5-1 summarizes information about clearing prices in the Regulation Market by month for 2006 and 2007. The annual average regulation clearing price dropped almost 50% from $24.03/MWh in 2006 to $12.67/MWh in 2007. This drop in regulation clearing price is in accordance with the expectation that, in the long term, suppliers would adjust to the new market design that was implemented in late 2005, shifts in supply, and the changes in fuel costs relative to late 2005**.**

Table 5-1
Regulation Market Clearing Prices, Summary Statistics, 2006 and 2007, $/MWh

Month		Average	Median	Minimum	Maximum
2006	Jan	44.13	39.56	5.00	100.00
	Feb	25.62	20.84	0.00	97.57
	Mar	27.96	22.96	0.00	92.48
	Apr	36.96	31.29	0.00	95.04
	May	30.66	27.00	0.00	76.90
	Jun	23.61	20.00	0.00	86.60
	Jul	14.29	13.00	0.01	63.37
	Aug	16.62	12.33	0.01	75.00
	Sep	12.05	11.96	0.00	50.86
	Oct	10.96	10.00	0.00	47.54
	Nov	20.19	11.86	1.34	100.00
	Dec	25.27	14.00	0.00	100.00
2007	Jan	16.38	10.00	1.51	100.00
	Feb	15.54	10.67	5.99	85.14
	Mar	14.81	10.17	2.75	99.00
	Apr	10.59	10.50	4.00	75.00
	May	13.62	10.49	4.00	100.00
	Jun	16.13	10.75	2.45	100.00
	Jul	10.82	10.25	7.87	60.10
	Aug	10.93	10.25	7.69	47.07
	Sep	10.25	10.00	7.17	100.00
	Oct	10.19	10.00	2.29	22.04
	Nov	10.83	10.00	6.09	99.00
	Dec	11.94	10.36	6.50	93.29

[94] The Ancillary Services Market project upgraded the ISO's market design and included changes to reserve markets and the Regulation Market. Additional information on ASM I is included in the ISO's *2006 Annual Markets Repor*t, available online at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2006/index.html.

5.4 Resource Selection Basis

The revised Regulation Market uses a selector program that assesses and ranks the offers from potential regulation suppliers for the upcoming hour. Regulation providers are selected on the basis of this ranking each hour. During the initial period of ASM I implementation, reviews by the market monitors identified minor inefficiencies in the regulation-selection process. The ISO proposed reforms to two elements of the selection software.[95] These revisions were filed with FERC in November 2006, and the ISO implemented the revisions on January 12, 2007, following FERC approval in early 2007.

The reforms improved the selection of regulation resources to meet the market design objective of minimizing costs. Specifically, eliminating the production cost component and adjusting the look-ahead penalty promote competitive bidding.

5.5 Regulation Market Conclusions

In 2007, the Regulation Market performed effectively. Total costs fell from $78.1 million in 2006 to $43.8 million in 2007. These results indicate that participants had adjusted to the new design, whereas during 2006, participants still were gaining experience with the revised market design. In 2007, the markets continued to provide sufficient amounts of regulation, and the New England Control Area fully complied with NERC reliability requirements for regulation.

The ISO and the external market monitor identified minor biases in the selection process and proposed market-rule revisions to address these shortcomings. Following FERC approval of the ISO's proposed revisions, the ISO implemented these changes in January 2007.

[95] David Patton and Pallas LeeVanSchaick. *2005 Assessment of the Electricity Markets in New England.* (Fairfax, VA: Potomac Economics, Ltd., 2006). Available online at http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2006/oct17182006/a9_reg_mkt_excerpt_from_2005_immu_report.pdf.

Section 6
Reliability Costs and
Peaking-Unit Safe-Harbor Bidding

To maintain daily system reliability, the ISO is required to make generator commitments that supplement the market-clearing outcomes. These commitments are compensated with Net Commitment-Period Compensation (NCPC) and tariff payments when necessary.[96] Total payments for daily reliability commitments increased slightly in 2007. To maintain long-term reliability, the ISO administers FERC-approved agreements, called Reliability Agreements, with certain generator owners. In 2007, both the megawatts covered by Reliability Agreements and the net cost of the agreements dropped dramatically. A third reliability mechanism, the Peaking-Unit Safe-Harbor treatment rules, which were implemented to provide incentives for generation resources necessary for reliability, were terminated with the introduction of capacity transition payment in late 2006.

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. Appendix B.1 provides additional data on tariff charges related to reliability.

6.1 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.[97] These requirements are codified in the NERC standards, NPCC criteria, and the ISO's operating procedures.[98] 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 ensure first-contingency systemwide reliability for which decommitment would pose a threat to the reliability of the system. These generators are committed to provide systemwide stability or thermal support, or to supply systemwide electric energy in peak hours, and then must stay on during later hours to satisfy minimum run-time requirements. The ISO also can commit resources to support second contingencies, to provide reactive power for voltage control or support, or to support local transmission. 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:

[96] *NCPC* is the methodology used to calculate payments to resources for providing operating or replacement reserves 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/. Also see Appendix B of this document.

[97] For more information on NERC standards, see https://standards.nerc.net (Princeton: NERC, 2007). For more information on NPCC standards, see http://www.npcc.org/regStandards/Overview.aspx (New York: NPCC Inc., 2007).

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

- 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 and regional first-contingency and out-of-merit energy 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.

This subsection discusses the process for making reliability commitments and includes total annual data for reliability commitments and generation for 2007 and annual reliability payments and cost allocations for the year. Data are compared with 2006 results.

6.1.1 Reliability Commitment Process

While some commitments may be made immediately after the Day-Ahead Energy Market clears, most are made through a commitment process called the Reserve Adequacy Analysis (RAA) process. The process is designed to maximize the opportunity for the market to respond and minimize the ISO's supplemental commitments to meet reliability criteria. The RAA begins after the reoffer period closes at 6:00 p.m. and is updated periodically throughout the operating day; commitments may be added or cancelled if reliability needs change during the operating day as a result of market response or other changed system conditions.

The first part of the RAA process is to evaluate 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 then will commit additional generation if the Day-Ahead Energy Market generation schedule, in combination with self-scheduled resources and off-line fast-start generation that can be committed, does not meet the real-time forecasted demand and reserve requirements. 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 offer at minimum output.

6.1.2 Reliability Commitment Results for 2007

The source of commitments, whether self-scheduled, economic pool-scheduled, or reliability, were relatively unchanged in 2007. Figure 6-1 shows total electric energy produced (MWh) by each type of commitment. Electric energy output from reliability commitments was 5.9% of total generation in 2007, ranging from a low of 2.3% in January to a high of 10.0% in November. Because a generator may be committed for reliability but become economic during the day, electric energy from a reliability commitment is not necessarily out of merit. The figures in this section include all megawatt-hours for the commitment period from each unit with a reliability commitment, irrespective of its in-merit portion. In 2007, more reliability commitments occurred during the RAA process and less during the Day-Ahead and Real-Time Energy Markets.

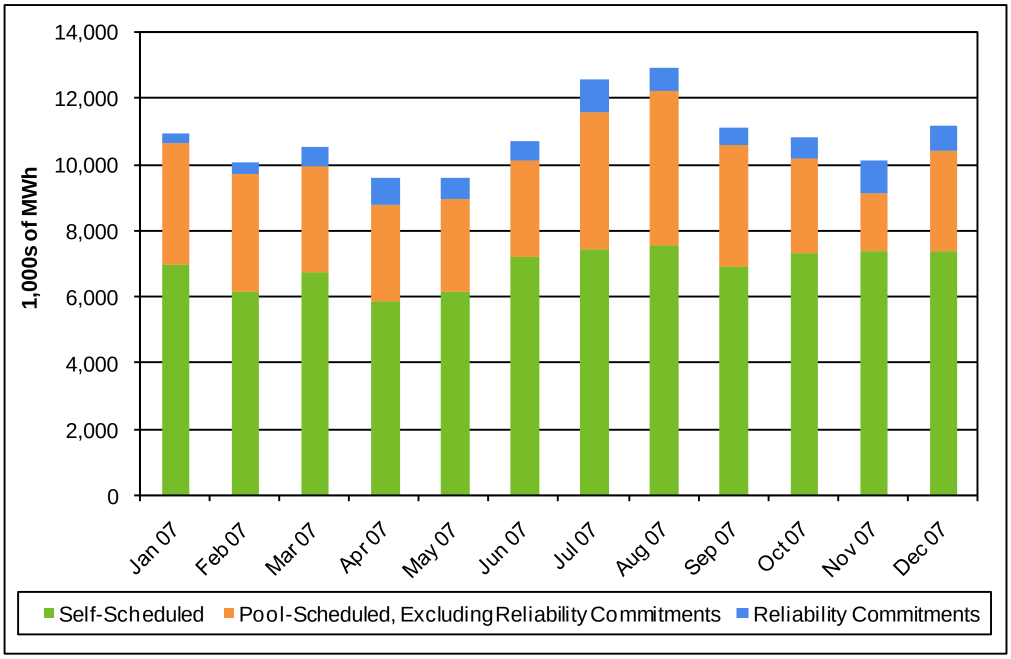

Figure 6-1: Electricity output from self-scheduled, economic pool-scheduled, and reliability commitments.

Figure 6-2 shows the electric energy output that resulted from reliability commitments in the Day-Ahead Energy Market, the RAA process, and the Real-Time Energy Market. Overall, the total electricity produced by generating units committed for reliability increased from 7.4 million MWh in 2006 to 7.7 million MWh in 2007. Electric energy output from reliability commitments made during the Day-Ahead Energy Market decreased 63% between 2006 and 2007. Energy output from reliability commitments made during the Real-Time Energy Market decreased by 50%. Energy output from commitments made during the RAA process increased by 73%.

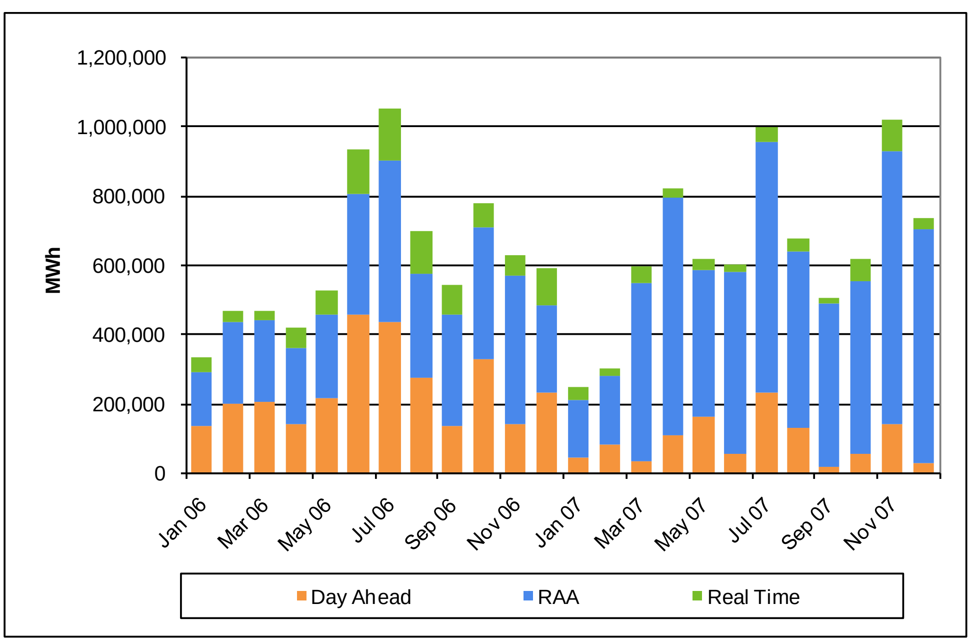

Figure 6-2: Total monthly electricity output from reliability commitments day ahead, the RAA, and in real time.

Most commitments made to supply local second-contingency reserves are in the Connecticut and NEMA load zones. Figure 6-3 shows total electricity output from commitments made to supply local second-contingency reserves by month and load zone. Only Connecticut and NEMA have daily evaluations of second-contingency reserve requirements in the operating procedures. Other areas are evaluated case by case when temporary transmission or resource outages significantly change the flows of energy relative to normal operations.

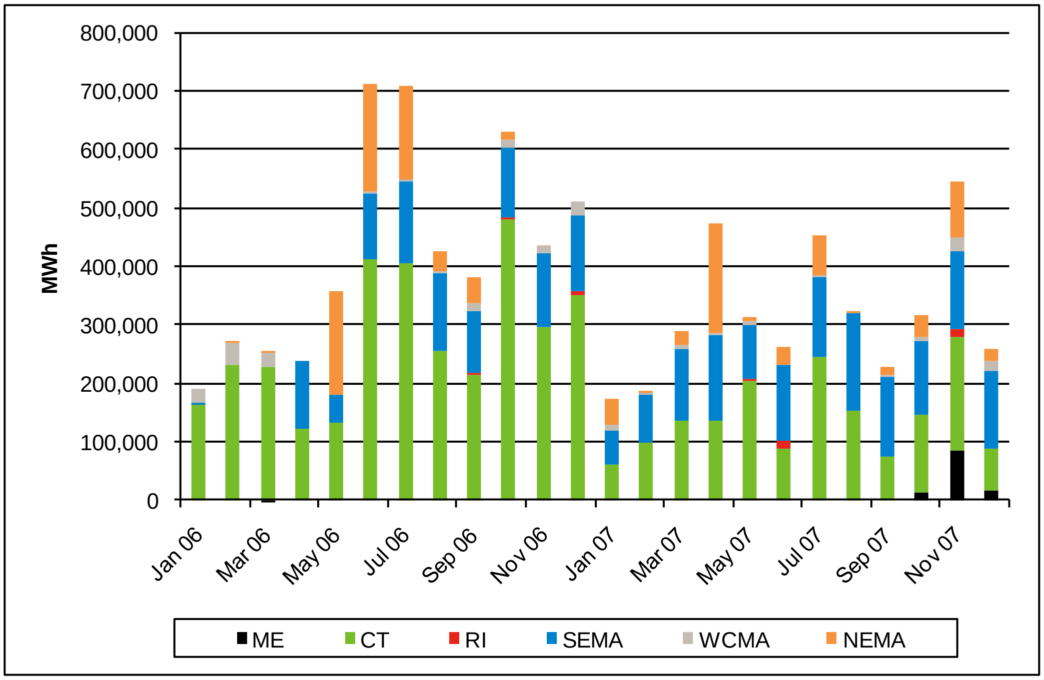

Figure 6-3: Total monthly electricity output from second-contingency commitments by load zone, 2006 and 2007.

Note: The quantity of electric energy produced in the WCMA load zone is too small, relative to other load zones, to be visible in the figure during some months.

In late 2005, the frequency with which SEMA resources were committed for second-contingency reliability increased. As shown in Figure 6-3, this increase in supplemental commitment of generating resources in SEMA continued through much of 2006 and then throughout 2007. The SEMA reliability commitments became necessary when No. 6 oil became more expensive than natural gas, as described in Section 2.4.2.2. This excluded units previously burning No. 6 oil as baseload from the Day-Ahead Energy Market dispatch. The *2006 Annual Markets Report* describes this pattern.[99] The ISO continues to work with transmission owners and other market participants to develop a plan to strengthen the local transmission system and other options that could decrease the need for out-of-market commitments in that area.

Transmission improvements reduced the need for local second-contingency commitments. Electric energy output from resources committed for second-contingency protection decreased 25% overall, dropping from 5.1 million MWh during 2006 to 3.8 million MWh in 2007. During both years, the majority of second-contingency commitments were made in the SEMA and Connecticut load zones, with NEMA resources also producing significant amounts of electric energy from reliability

[99] AMR06 is available online at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html.

commitments. During 2007, 42% of the megawatt-hours from second-contingency-committed resources were from resources located in the Connecticut load zone, 39% were from SEMA resources, and 14% were from resources in the NEMA load zone. This continues a pattern of decreased energy output from resources in the NEMA load zone committed for second-contingency protection. The reduction in commitments and energy output for second-contingency protection are the result of transmission improvements made in late 2006 and early 2007. The decrease in commitments in the Connecticut load zone between 2006 and 2007 was partly due to the completion and operation of Phase 1 of the SWCT 345 kV Reliability Project.

Figure 6-3 also shows that resources in the WCMA load zone produced small amounts of electric energy in several months during 2006 and most months of 2007. This output is attributable to resources committed to support second contingencies in western Massachusetts caused by transmission system outages that occurred throughout the period. These resources were committed on the basis of an analysis that is performed when particular transmission elements are out of service.

Figure 6-4 shows, by month and by load zone, the total electric energy output from commitments made during the reporting period to provide reactive power. These commitments provide high-voltage control or low-voltage support. The commitments for voltage control generally are needed when demand levels are low, while the commitments for voltage support are needed during high-demand periods.

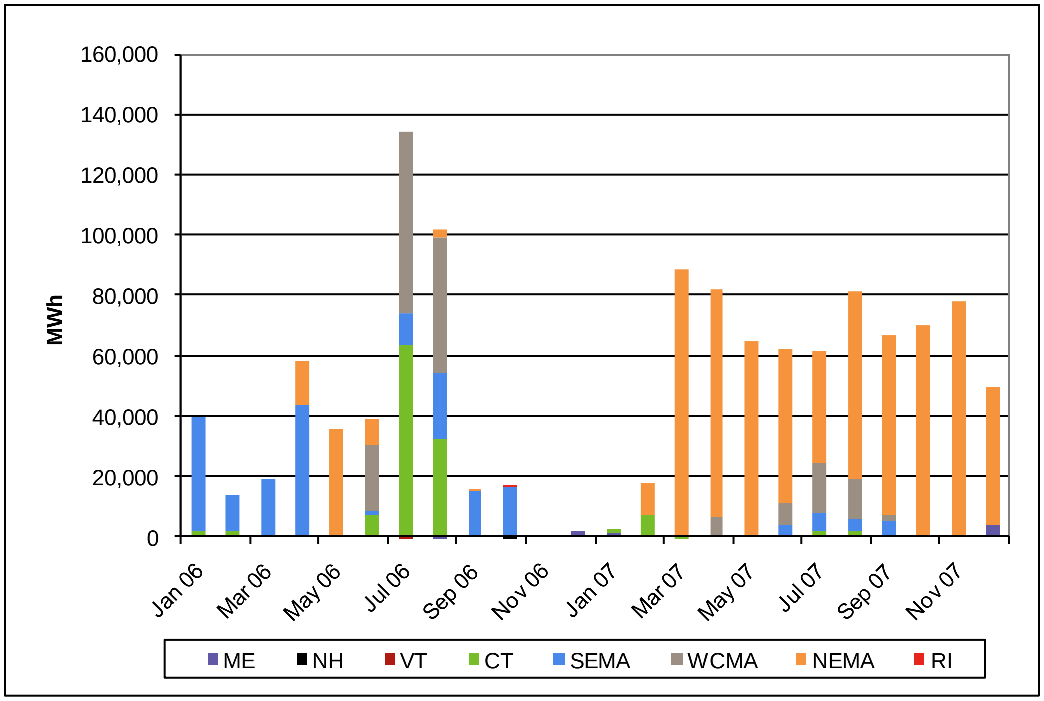

Figure 6-4: Total monthly electricity output from voltage commitments by load zone, 2006 and 2007.

The total output produced for voltage support and control in 2007 increased relative to 2006, rising from just under 500,000 MWh in 2006 to about 726,000 MWh in 2007. The increase is attributable to

VAR commitments in the NEMA load zone.[100] During 2006, resources in the NEMA load zone with Reliability Agreements included provisions for self-scheduling that reduced the need for VAR commitments. With the termination of the Reliability Agreements, the persistent need for VAR commitments in the NEMA load zone returned. All other load zones experienced decreases in generation output for voltage support and control. Phase 1 of the Southwest Connecticut 345 kV Reliability Project reduced the need for reliability commitments within Connecticut, improving transmission between the Norwalk/Stamford subarea and the rest of Southwest Connecticut. Phase 2 of the project, scheduled for completion no later than December 2009, will improve transmission between Southwest Connecticut and the rest of Connecticut.

6.1.3 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, including start-up and no-load costs. This ensures that generators providing electric energy needed for reliability but experiencing lost opportunity costs or overall revenue shortfalls 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 commitments (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. First-contingency reliability payments are paid to eligible units that provide operating reserves and are not flagged, or designated, to provide second-contingency reliability or to meet requirements for voltage or distribution reliability.

6.1.3.1 Daily Reliability Payments for 2007

Figure 6-5 shows total monthly reliability payments for 2006 and 2007 by financial settlement category, and Table 6-1 shows the total daily reliability payments by category with the percentage change between years. The daily reliability payments show a pronounced dip between 2006 and the beginning of 2007. The rise beginning in March 2007 is associated with the increasing price of No. 6 oil (see Section 2.4.2.2). Reliability resources running No. 6 oil became increasingly expensive as a result.

[100] *VAR* stands for "voltage-ampere reactive" and is a unit of measure of reactive power, which provides voltage support and control.

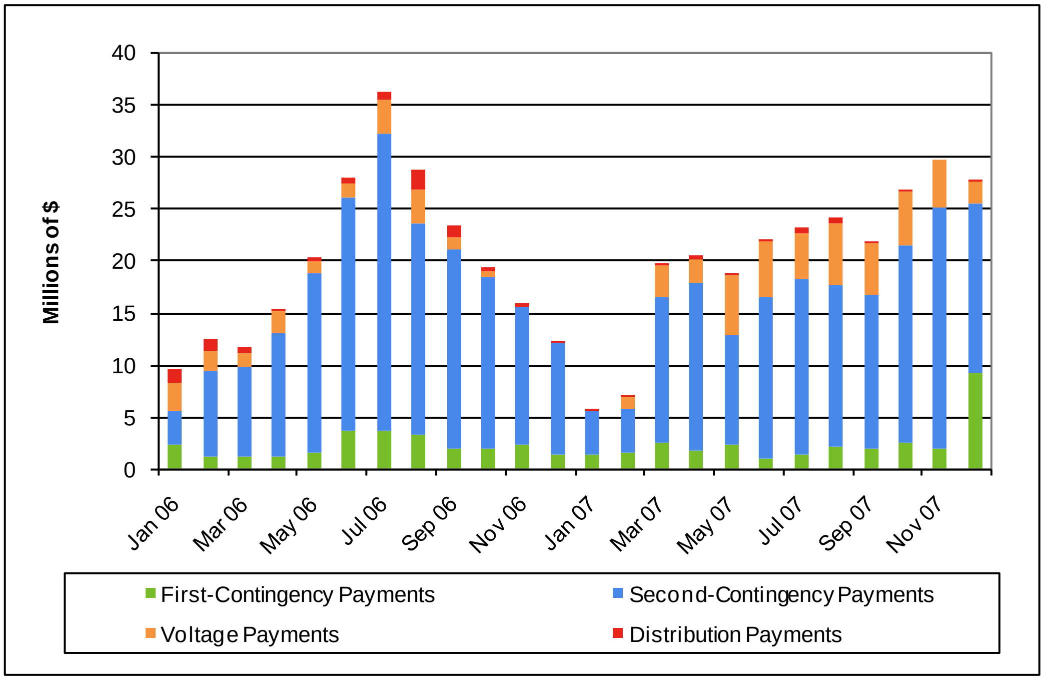

Figure 6-5: Daily reliability payments by month, January 2006 to December 2007.

Table 6-1
Total Daily Reliability Payments, 2006 and 2007, Millions $

Payment Type	2006	2007	Difference	% Change
First-contingency reliability payments	25.2	29.6	4.4	18%
Second-contingency reliability payments	179.9	169.5	–10.5	–6%
Distribution	8.6	1.8	–6.8	–79%
Voltage	19.0	46.0	27.0	142%
Total	**232.8**	**246.9**	**14.1**	**6%**

Total payments in 2007 were up 6% ($14.1 million) compared with 2006 payments. Second-contingency payments were down in 2007, dropping from $179.7 million in 2006 to $169.5 million in 2007. Payments for resources committed to support local distribution networks were down by a large percentage (79%); however, in total value, the decrease only represents $6.8 million. First-contingency payments increased 4.4% from 2006 levels, growing from $25.2 million to $29.6 million. This increase is due largely to the results for December 2007 when the outage of a natural gas facility on Sable Island resulted in the ISO committing numerous oil-fired generators to ensure system reliability (see Section 2.5.4). Without this event, first-contingency payments would have been lower in 2007 than in 2006. The increase in overall daily reliability payments was driven by a large increase in the cost of payments to compensate generators providing voltage support, growing 142%, from $19 million in 2006 to $46 million in 2007.

Table 6-2 shows the breakdown of second-contingency payments for 2006 and 2007 by the load zone requiring commitments for second-contingency protection. The SEMA load zone showed a large increase in second-contingency payments, growing from $85.2 million in 2006 to $108.0 million in 2006. Connecticut, WCMA, and NEMA all had lower second-contingency payments. The Maine and Rhode Island load zones each required payments for second-contingency support as a result of transient events. The combined total dollar value was less than $2.5 million.

Table 6-2
Second-Contingency Reliability Payments by Load Zone, 2006 and 2007, Million $

Load Zone	2006			2007		
	Day Ahead	Real Time	Total	Day Ahead	Real Time	Total
ME					2.1	2.1
CT	2.5	56.8	59.4	1.3	34.0	35.3
RI					0.2	0.2
SEMA	4.4	80.8	85.2	2.0	106.0	108.0
WCMA	0.0	2.9	2.9		1.7	1.7
NEMA	2.3	30.2	32.5	0.9	21.3	22.3
System Total	**9.3**	**170.7**	**179.9**	**4.2**	**165.3**	**169.5**

The increase in payments to resources supporting second contingencies in SEMA was the result of the requirement to commit resources for second-contingency reliability, as mentioned in Section 6.1.2. The reliability commitments and resulting daily reliability payments paid to support the WCMA, Maine, and Rhode Island load zones were the result of temporary transmission outages. These temporary outages in turn resulted in import restrictions that required local generation to provide second-contingency support until the transmission infrastructure was back in service.

6.1.3.2 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 the ISO's *Open Access Transmission Tariff*, whereas the allocation of first- and second-contingency payments is governed by Market Rule 1.[101] 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 owner requesting the generator commitment. 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 or do not follow 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 June 2007 FERC Settlement Agreement, a two-condition, two-tiered threshold criterion was established that can

[101] The ISO's tariffs and Market Rule 1 are available online at http://www.iso-ne.com/regulatory/tariff/index.html.

change the allocation of real-time second-contingency charges.[102] At no time during 2007 were all the conditions of the Settlement Agreement satisfied; therefore, all second-contingency costs were allocated based on the default-allocation method.

Table 6-3 shows the average allocation of first-contingency reliability charges by month for 2007. These averages are calculated using data from days with charges. Table 6-4 shows the 2007 average allocation of second-contingency charges by month. Allocations shown for Connecticut are for the entire state and are not subarea specific.

Table 6-3
Average First-Contingency Daily Reliability Allocations for Days with Charges, 2007, $/MWh

Month	Day Ahead	Real Time
Jan	0.01	0.35
Feb	0.06	0.34
Mar	0.04	0.60
Apr	0.01	0.47
May	0.04	0.52
Jun	0.01	0.19
Jul	0.02	0.26
Aug	0.01	0.41
Sep	0.02	0.40
Oct	0.06	0.48
Nov	0.01	0.42
Dec	0.11	2.01
Annual Average	**0.03**	**0.54**

[102] 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).

Table 6-4
Average Second-Contingency Daily Reliability Allocations for Days with Charges, 2007, $/MWh

Month	ME		CT		SEMA		WCMA		NEMA	
	Day Ahead	Real Time	Day Ahead	Real Time	Day Ahead	Real Time	Day Ahead	Real Time	Day Ahead	Real Time
Jan	0.00	0.00	0.15	0.57	1.40	3.25	0.00	0.41	0.00	1.87
Feb	0.00	0.00	0.20	0.43	0.96	3.98	0.00	0.18	0.00	2.85
Mar	0.00	0.00	0.33	2.40	2.78	4.83	0.00	0.55	0.66	2.95
Apr	0.00	0.00	0.35	1.79	0.00	5.96	0.00	0.35	3.06	3.92
May	0.00	0.00	0.57	1.53	0.03	6.07	0.00	0.49	0.00	2.97
Jun	0.00	0.00	0.14	2.15	1.16	7.83	0.00	0.11	0.00	3.39
Jul	0.00	0.00	0.15	1.13	0.97	7.09	0.00	0.42	0.00	2.22
Aug	0.00	0.00	0.12	0.94	1.05	8.28	0.00	0.00	0.00	2.04
Sep	0.00	0.00	0.15	1.81	0.91	8.76	0.00	0.42	0.00	2.48
Oct	0.00	1.34	0.21	2.54	0.87	9.36	0.00	0.28	2.02	3.29
Nov[(a)]	0.00	1.64	0.18	1.25	3.60	11.92	0.00	0.34	0.00	3.89
Dec	0.00	2.00	0.23	1.71	0.12	8.14	0.00	0.59	2.95	3.35
Annual Average	**0.00**	**1.66**	**0.23**	**1.52**	**1.36**	**7.12**	**0.00**	**0.38**	**2.17**	**2.94**

(a) A $2.18/MWh allocation for the Rhode Island load zone during November is excluded from the table.

6.1.4 Daily Reliability Commitment and Costs Conclusions

The ISO continues to need out-of-market commitments and associated payments to maintain reliable operation of the system. Electric energy market outcomes play an important role in the need for out-of-market commitments for reliability. 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. These market-based effects and participant self-scheduling led to the majority of the changes in output generated by resources committed for second-contingency and voltage services.

Total daily reliability payments for the year increased from $232.7 million in 2006 to $246.9 million in 2007 as a result of higher voltage payments made to resources in the NEMA load zone and, to a lesser extent, higher first-contingency payments. The pattern of second-contingency payments to resources in the Connecticut and SEMA load zones continued in 2007, while the majority of voltage payments were made to resources in the NEMA load zone. These daily reliability payments reflect out-of-merit operation that dampens price signals emanating from constrained areas on the system and decreases the incentives for flexible, fast-start capacity to locate and operate in those areas. The ISO and transmission-owning utilities will continue to take steps to reduce the need for out-of-market payments, while ensuring that generators necessary for reliable operation of the system are compensated for their costs. Additional transmission projects are underway in the Connecticut area that should reduce the need for out-of-merit operation. However, cost-effective infrastructure improvements never will completely eliminate the need for out-of merit operations. The ISO will continue to refine market rules with respect to out-of-merit operation to ensure that generating units following dispatch instructions are fairly compensated and that appropriate price signals are sent to local resources.

6.2 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 the current market prices do not fully and appropriately signal the need for new infrastructure.

The Reliability Agreements in effect as of December 2007 are for full cost of service—the generator recovers its fixed costs in a monthly payment and its variable costs through electric energy offers made at short-run marginal cost.[103] 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.

6.2.1 Reliability Agreement Results

As of November 28, 2007, Reliability Agreements were in effect for nine generating stations in two load zones, comprising 3,203 MW of capacity.[104] This represents 10% of the total systemwide capacity. As shown in Table 6-5, the majority of capacity with Reliability Agreements is located in the Connecticut load zone (2,664 MW), and the remaining 539 MW is located in the WCMA load zone. This represents a significant change from previous years when the NEMA load zone also had a number of resources under Reliability Agreements. The Reliability Agreements with Mystic units #8 and #9 terminated on January 1, 2007, and the agreement with the Mirant-Kendall station units terminated on July 12, 2007. The Settlement Agreement with Salem Harbor terminated on July 22, 2007, leaving no capacity in the NEMA load zone under a Reliability Agreement. In addition to the Reliability Agreement terminations in the NEMA load zone, three stations in Connecticut with a total capacity of 738 MW had Reliability Agreements terminated in 2007. Figure 6-6 shows the change in generating capacity with Reliability Agreements since 2002. Between 2006 and 2007, the total capacity under Reliability Agreements decreased by 24%.

[103] The Salem Harbor station had a FERC Settlement Agreement preventing the shutdown of the units before October 1, 2008, with a guaranteed payment of $6.75 million distributed over a two-year period ending July 2007.

[104] 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.

Table 6-5
Percent of Capacity under Reliability Agreements, Effective and Pending, November 2007

Load Zone	2007 CELT Summer Seasonal Claimed Capability (MW)	2007 Capacity with Cost-of-Service Reliability Agreement	2007 Capacity under Reliability Agreements as % of 2007 SCC
Maine	3,234	0	0%
New Hampshire	4,091	0	0%
Vermont	932	0	0%
Connecticut	7,535	2,664	35.4%
Rhode Island	1,839	0	0%
SEMA	5,694	0	0%
WCMA	3,869	539	13.9%
NEMA	3,571	0	0%
New England Total	**30,765**	**3,203**	**10.4%**

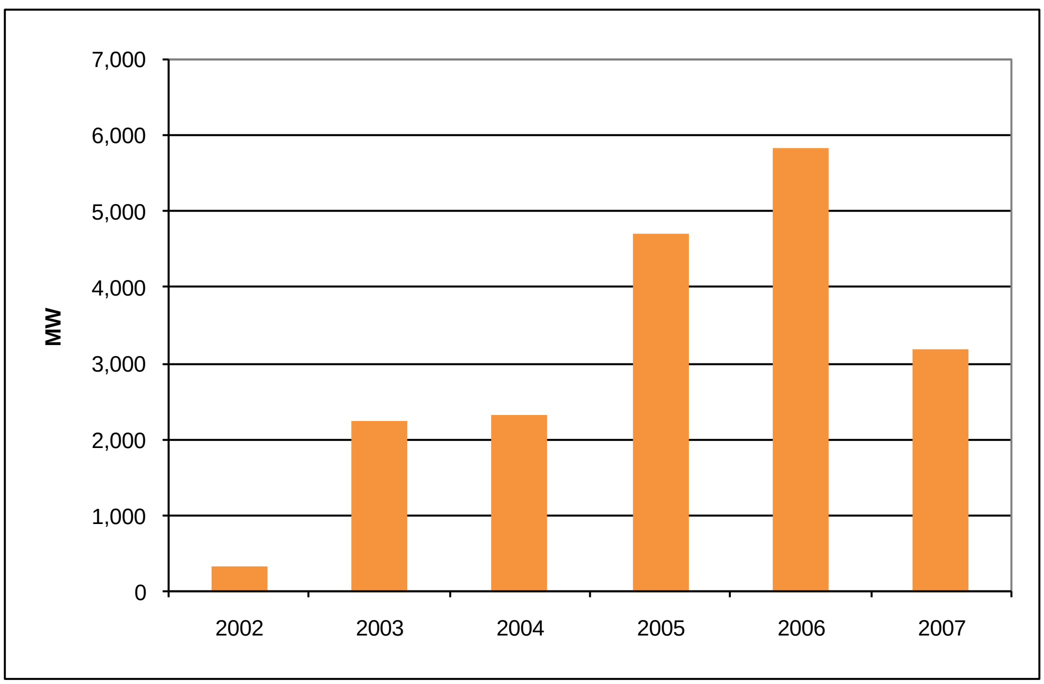

Figure 6-6: Generating capacity with FERC-approved Reliability Agreements.

The total annualized fixed-cost requirement for all resources with Reliability Agreements effective December 31, 2007, was $295.8 million, a decrease of almost 56% from the 2006 level of $666.9 million.[105] 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. The actual Reliability Agreement payments made to a generating unit with a Reliability Agreement are reduced by the market revenues that exceed its offers. This results in Reliability Agreement payments plus market revenues that are equal to FERC-approved fixed and variable costs. Table 6-6 shows the annual sum of monthly net payments for 2003 through 2007.

Table 6-6
Net Reliability Agreement Payments, System Total, Million $[(a)]

	2003	2004	2005	2006	2007
Payment	83.4	177.6	223.6	347.7	143.1

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

The large decrease in net Reliability Agreement payments is due to the reduction in capacity that operates under cost-of-service Reliability Agreements and the fact that FERC settlements lowered the approved annualized fixed-cost recovery of a number of the resources with agreements.

6.2.2 Reliability Agreement Conclusions

The year 2007 represents the first time since the introduction of the SMD markets in 2003 that the total capacity under Reliability Agreements and net payments decreased. Reliability Agreements do not send useful investment signals to potential new entrants. While FERC has accepted Reliability Agreements, they are intended as interim measures to ensure that generators needed for reliability are recovering adequate revenues until a market-based mechanism is implemented that appropriately compensates generators providing reliability services.

The 2007 results showing a decrease in the reliance on Reliability Agreements are an important milestone. The economic signals being sent by the recently revised Forward Reserve Market and the capacity transition payments, in combination with the ISO's planning process, are leading to generation and transmission infrastructure improvements that have reduced the need to rely on out-of market cost-of-service agreements.

6.3 Peaking-Unit Safe-Harbor Bidding

On April 25, 2003, FERC issued its *Order Accepting, in Part, Requests for Reliability Must-Run Contracts and Directing Temporary Bidding Rules* (Devon Order).[106] The Devon Order directed the ISO to replace the existing rules covering mitigation in chronically congested areas, referred to as *Designated Congestion Area* (DCA) rules, with new rules that apply special mitigation formulas to units in DCAs with low capacity factors (i.e., an annual capacity factor of less than 10% in 2002).

[105] A full year of annualized fixed cost is included in this total for resources with Reliability Agreements effective December 31, 2007, regardless of when the agreement became effective during the year.

[106] 103 FERC ¶ 61,082 (Apr. 25, 2003).

On June 1, 2003, the ISO implemented *Peaking-Unit Safe-Harbor* (PUSH) offer rules, which allow owners of low-capacity-factor generating units located in DCAs to include levelized fixed costs in their electric energy offers without risk of mitigation. The rules were intended to increase opportunities for fixed-cost recovery and to produce signals for investment through higher LMPs in these areas during periods of electric energy scarcity.[107]

Since the PUSH mechanism was established, several significant changes have taken place in the New England markets. First, FERC approved a new locational Forward Reserve Market, which was implemented on October 1, 2006 (as discussed in Section 4). In the FRM auctions, generating units in constrained areas that are providing reserves are being paid $14.00/kW-month. Thus, this new market is clearly compensating generators with resources in constrained areas and providing strong investment signals for new resources. Second, also on October 1, 2006, the ISO implemented a new real-time dispatch system, which provides for the co-optimization of energy and reserves (see Section 0). As a result, LMPs now reflect additional costs associated with redispatching the system to provide real-time reserves in constrained areas. Finally, starting on December 1, 2006, the FERC-approved Forward Capacity Market Settlement Agreement has been providing generators with transition payments that started at $3.05/kW-month and will increase thereafter (see Section 3.5). Given these changes and the additional compensation and economic signals they provide, the ISO and NEPOOL proposed to eliminate the PUSH bidding mechanism.[108] FERC accepted this proposal, with an effective date of June 19, 2007, subject to refund and further order.[109]

When the PUSH rule was terminated, 42 active generating units in the congested areas of NEMA and Connecticut met the low-capacity-factor (based on 2002 capacity factors) and DCA-location criteria for PUSH treatment. This total includes multiple units at the same station. Of these 42 generating units, 16 were offering their generation under PUSH rules with positive fixed-cost adders.

When the PUSH units were dispatched out of merit, they were compensated through first- and second-contingency reliability payments for any shortfalls between their offers and their electric energy market revenues. Between January 1 and June 19, 2007, PUSH units received approximately $7.6 million in second-contingency reliability payments and about $300,000 in first-contingency reliability payments.

[107] Additional information about PUSH is available online at http://www.iso-ne.com/markets/mktmonmit/implmnt/push_imp/index.html.

[108] The joint filing by the ISO and NEPOOL, *Proposed Elimination of the Peaking Unit Safe Harbor Mechanism,* Docket No.ER07 (November 14, 2006), can be found online at http://www.iso-ne.com/regulatory/ferc/filings/2006/nov/er07-219-000_11-14-06_push.pdf.

[109] *Order Accepting and Amending Tariff Revisions and Establishing Reporting Requirement*. FERC Docket No. ER07-219-000. 118 FERC ¶ 61,018 (January 12, 2007). Available online at http://www.iso-ne.com/regulatory/ferc/orders/2007/jan/er07-219-000_1-12-07_push.pdf.

Section 7
Financial Transmission Rights

The ISO conducts the annual and monthly markets for financial transmission rights (FTRs). For the ISO, FTRs fulfill three objectives. They provide a structure for the ISO to redistribute the congestion portion of the revenues collected from participants in excess of what is paid out in LMP-based energy markets to transmission customers and congestion-paying entities. They also provide a tool for participants to hedge Day-Ahead Energy Market congestion costs as well as a financial instrument to arbitrage the difference between expected and actual day-ahead congestion components. While fulfilling these objectives, 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 on to participants.

Financial Transmission Rights are by design a financial instrument. The ISO conducts FTR auctions that incorporate assumed system information based on expected transmission outages and FTR offers that will provide an efficient outcome, rather than relying on private markets and bilateral trading.

In 2007, $122 million were collected total from the one annual and 12 monthly auctions. These revenues were distributed to participants in accordance with the Auction Revenue Rights (ARR) allocation process set out in Appendix C of Market Rule 1.[110] Auction outcomes appear efficient based on average path profits that approached zero for both on-peak and off-peak FTRs. The hedging performance of FTRs was less than 100% in 2007. After year-end distributions of the Congestion Revenue Balancing Fund (CRBF), only 95% of the total amounts accrued throughout the year was paid to FTR holders.

This section describes FTRs, the organization of the FTR auctions, and the use of the FTR instrument either to hedge congestion costs or as a financial arbitrage instrument. Various operational aspects of the FTR market and auctions are summarized. Also discussed are the results of the 2007 FTR auctions, the allocation of the auction revenues, and the performance of the ISO's FTR markets during 2007. Appendix C of this document provides a more detailed breakdown of the monthly Congestion Revenue Balancing Fund and a flow diagram outlining the interactions of the megawatts awarded from the FTR auction, the energy markets settlements, and FTR settlements.

7.1 Description of FTRs

FTRs can be acquired to and from any pricing point on the transmission network. Each FTR is for either all on-peak or all off-peak hours and is defined by a pair of points on the transmission grid. The locations of FTR origins are called *source* points, and the locations of delivery are *sink* points. Each FTR also has a specified megawatt quantity and duration, for either a full year or any one month.[111] The holder of each FTR is entitled to receive, or obligated to make, a flow of payments over the specified duration. An FTR becomes a financial obligation when the LMP at the source point is higher than the LMP at the sink point.

Rather than directly allocating FTRs, each year, the ISO conducts an annual FTR auction and 12 monthly FTR auctions for participants to buy and sell FTRs. Annual FTRs are offered in a single

[110] Appendix C of Market Rule 1 is available online at http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

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

auction for the ensuing year, and additional monthly FTRs are offered before each month for on-peak and off-peak periods during the year. (In addition, the ISO facilitates bilateral trades by providing a forum for posting bid and ask prices.)

The supply of FTRs made available during each auction is an important ISO policy decision. During the annual auction, the quantity of FTRs the ISO awards equals 50% of the predicted power-transfer capacity of the transmission system that the FTRs will use. In each monthly auction, the ISO awards available remaining capacity up to 95% of the expected power-transfer capacity for the upcoming month after accounting for planned transmission outages. This power-transfer capacity is not based on a set "contract path"—instead, the transfer capacity is based on all the indirect paths between the source and sink points of each awarded FTR.

The FTR market includes an additional feature that allows participants to acquire *counterflow* FTRs. With a counterflow FTR, the participant acquires power-flow capacity against the prevailing direction of power flows, represented by other participants' offers in the auction. As a result, the participant takes on an expected obligation to pay the ISO in the monthly FTR settlements and is compensated by receiving a negative price in the auction settlement. Any FTR path that clears with a negative auction price is considered a counterflow FTR regardless of whether the participant makes a negative or positive offer into the auction.[112] Participants that attempt to acquire counterflow FTRs expect that the revenues they receive from the auction will exceed the monthly payments they expect to owe as a result of the obligatory feature of the ISO's FTR structure. Counterflow FTR sales can increase the efficiency of the auction outcome by increasing the supply of FTRs in the predominant direction of flows.

For the annual auction of FTRs, each participant submits bids to buy quantities of specific FTRs.[113] A bid price to buy is interpreted as the maximum price a participant is willing to pay for the FTR path. The auction software calculates a price at every node on the transmission system. The price of a particular FTR is calculated as the difference between the nodal price at the FTR's sink and source points. Participants whose FTR bids are accepted are awarded the FTR in an amount based on the calculated path prices and are required to pay the ISO.[114] The key task of the auction software is to maximize the auction revenue to be collected while maintaining simultaneous feasibility of the power flows associated with awarded FTRs.

The auction software used is similar to the software that optimizes the dispatch of electric energy in the day-ahead market. Each bid to buy an FTR is interpreted as though it is a bid to transmit energy from the source location to the sink point. If the source-to-sink path is in the direction of expected flows, the FTR likely will have a positive price. If bidding participants expect the source-to-sink path to be in the opposite direction of net power flows (i.e., counterflow), the FTR will have a negative price. The software then finds the set of accepted bids that maximizes the total gains from trade, subject to the transmission constraints.

In the monthly auctions, participants can sell FTRs they previously acquired in the annual auction. Sellers do not have to be matched with buyers in sales of annual capacity in the monthly markets. An FTR sold back to the market affects all FTR prices and quantities because the sold FTR's capacity

[112] Participants can offer negative-priced bids to acquire a counterflow FTR, or they can bid a positive price in the auction, but the clearing prices result in a negative path price for the FTR.

[113] Participants that offer negative prices are in effect offering to sell FTR capacity.

[114] Negatively priced FTRs result in a payment to the participant.

increases the transmission capacity available to all participants, which affects monthly auction power flows. This organized combinatorial characteristic of the monthly auction provides more liquidity than a secondary auction restricted to reselling the same source-sink-paired FTR.

An important policy objective of the ISO is to ensure that the transmission elements assumed to be in service (i.e., the assumed transfer capacities used in the auctions) are accurate predictions of the properties of the transmission system that will prevail in the subsequent day-ahead markets for energy. These parameters naturally vary, but the aim is to estimate average properties. Assuming fewer outages than actually occur can result in awarding too large a quantity of FTRs, which can result in underpayment to FTR holders. Likewise, assuming too many outages relative to actual conditions in the day-ahead market will result in awarding fewer FTRs, which can require the distribution of excess congestion revenues to load-serving entities at the end of the year.

FTRs acquired in either the annual or one of the monthly auctions are settled based on the results of the Day-Ahead Energy Market. Each FTR settlement is equal to the congestion component of the hourly day-ahead locational marginal price (i.e., the nodal price) at the FTR's sink point minus this component at the FTR's source point. The FTR settlement is a positive target allocation (PTA) when this difference is positive and the ISO distributes congestion revenue to the holder in an amount equal to the price difference multiplied by the megawatt quantity of the FTR. The FTR settlement is a negative target allocation (NTA) when the difference is negative and the participant is required to pay money into the Congestion Revenue Fund in an amount equal to the price difference multiplied by the megawatt quantity. Holding an FTR is associated with risk because any FTR can become an almost limitless liability (e.g., a very large NTA) as a result of unexpected transmission conditions.

7.2 Participant Applications for FTRs

This section explains the mechanisms for two useful FTR applications: using FTRs as a hedge against day-ahead market congestion charges and as a financial instrument to arbitrage the differences between FTR auction outcomes and actual day-ahead congestion components.

7.2.1 Use of FTRs to Hedge Congestion Charges

In an LMP-based market, a difference between the hourly locational prices at two points indicates the presence of some combination of losses and congestion on the system. In a simplified case that ignores transmission losses, a difference in LMPs indicates that the transmission system is congested at some point—and the lowest-cost generation source available to serve additional load cannot produce more megawatts on the system without violating a transmission constraint. The advantage of locational marginal pricing is that it ensures the minimization of the total cost to meet all loads subject to all the transmission constraints. For many participants, however, it introduces the practical problem that hourly locational marginal prices are volatile and, in particular, that the marginal congestion charges represented by locational price differences are volatile. But this problem can be remedied by using FTRs as a financial hedge, as illustrated in the following example.

Example: A load-serving entity located in an area that is occasionally import-constrained enters into a bilateral agreement with a distant generator to buy some of the electric energy the LSE needs to serve its customers. The agreement specifies that the transaction will be delivered at the New England Hub (a location that was created to facilitate trading), and the contract will be settled through the ISO systems using an internal bilateral trade. In this scenario, the LSE would have an energy settlement with the ISO that consisted of a payment to the ISO of the load-zone price and the receipt of a payment of the Hub price. Ignoring marginal loss costs, this leaves the LSE with the risk that the congestion component of the zonal price it pays will be greater than the congestion component of the Hub price it receives.

The bilateral agreement provides a hedge for the risks associated with the energy component of the LMP, and an FTR can hedge the congestion component difference of the price risk associated with serving the load, providing a complete hedge for the expected energy transactions.[115] By purchasing an FTR at the auction price between the Hub and its load zone, the LSE expects to lock in its congestion costs at an amount equal to the auction price. For every hour that the bilateral contract and the FTR overlap, the congestion component differences of the energy market settlement are offset by the FTR settlement. This holds regardless of the actual direction of congestion. The energy market settlement equals the Hub congestion component (source) minus the zone congestion component (sink), while the FTR settlement equals the opposite: the zone congestion component minus the Hub congestion component. If congestion is in the expected direction (Hub to the load zone), the energy market difference in congestion components will be positive, and the utility will pay the ISO in the energy market but receives the same amount through the FTR settlement. If the congestion reverses direction (load zone to Hub), the difference is negative, and the ISO pays the LSE in the energy market, but the LSE is obligated to pay the same amount in its FTR settlement. The net effect is that the utility prepays the congestion at the auction price, and the FTR and congestion portion of the energy settlements cancel each other out.[116] FTRs can be useful in many other situations, as well.

7.2.2 Use of FTRs as a Financial Arbitrage Instrument

FTRs also provide the opportunity for participants to arbitrage the difference between their expectations of congestion patterns and those of other market participants bidding the FTR auction. Participants that believe the market will under-value a path in the auction (i.e., set an auction price lower than expected congestion) can arbitrage this expected difference by buying the FTR with the expectation that the flow of payments from the energy market (positive target allocations) will exceed the auction cost. Alternatively, participants that believe the market will over-value a path (set an auction price greater than expected congestion) can bid negative (sell short) and acquire a counterflow FTR. In this case, a participant would expect to receive from this auction an amount greater than the expected negative target allocation it will be obligated to make in the energy market (the expected flow of payments over the term of the FTR).

7.3 FTR Market Operations and Auction Revenue Rights

Because the FTR markets are entirely financial, the central operational concern is to “follow the money.” Figure 7-1 shows the flow of revenues and megawatts associated with the FTR auctions. Net revenue from the annual and monthly FTR auctions goes into an auction revenue fund. This net revenue is the sum of prices paid for FTRs minus the sum of prices paid out for FTR sales (both counterflow sales and the resale of FTRs purchased in the annual auction). These funds are allocated to participants according to the process specified in the Auction Revenue Rights sections of Appendix C of Market Rule 1. The ARR distribution rules call for allocating the auction revenues to all congestion-paying LSE and transmission customers that have supported the transmission system

[115] Technically, it is not a complete hedge because losses are not hedged in the example. However, as previously mentioned, losses are fairly predictable.

[116] The congestion payments made in the Day-Ahead Energy Market can be quite different than the auction cost converted to $/MWh. The auction cost is based on the overall expectation of congestion, while the congestion payments are based on the actual congestion on the system, which can vary greatly from expectations formed at the time of the auction.

by first allocating auction revenues to entities eligible for Qualified Upgrade Awards (QUAs).[117] The remaining revenues are then allocated to the following three categories:

- **Excepted transactions**—special grandfathered transactions (listed in Attachments G and G-2 of the ISO *Open Access Transmission Tariff*)[118]
- **Load share—**congestion-paying entities in proportion to their real-time load obligation at the time of the system's coincident peak for the month
- **NEMA contracts**—congestion-paying entities in proportion to their real-time load obligations with some reallocations as a result of other long-term contracts that include delivery in northeastern Massachusetts (listed in Exhibit 1 of Market Rule 1, Appendix C)

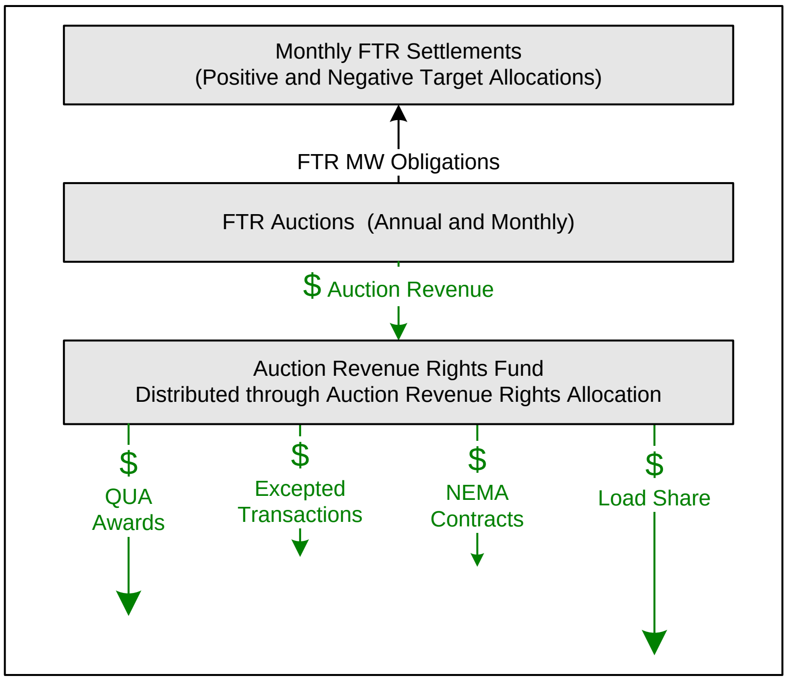

Figure 7-1: Flow of revenues and megawatts from the FTR auctions.

During the year, the ISO maintains a Congestion Revenue Balancing Fund that tracks day-ahead and real-time congestion revenues (RTCRs) along with payments owed to holders of FTRs (positive allocations) and payments due from holders of FTRs (negative allocations). Assuming the monthly net congestion revenue and negative target allocations are sufficient, the ISO pays holders of positive target allocations the amount they are owed. Any surplus is accumulated in an interest-bearing year-end balance fund. If the net congestion revenue and negative target allocations are insufficient to cover 100% of the monthly positive target allocations, the ISO prorates all positive target allocations and maintains a record of the payment shortfalls. At the end of the year, the ISO distributes the

[117] Entities that are eligible for QUAs have built transmission infrastructure and have chosen to receive the incremental auction payments resulting from the infrastructure improvement rather than recovering the development and maintenance costs through Network Service Rights tariff payments.

[118] Appendix C to Market Rule 1 provides that holders of certain contracts, called *excepted transactions*, have an option to be assigned ARRs in the initial stage of the allocation process. Such ARRs are from a combination of the generation sources and external nodes to the node(s) of the load consistent with the excepted transaction. This option is available on request for the earlier of 10 years following the SMD effective date or termination of the excepted transaction.

surplus revenues that are accumulated in the year-end balancing fund to compensate positive target-allocation holders for their monthly shortfalls plus interest. Any revenues remaining after shortfalls have been repaid are allocated to entities that paid congestion charges during the year. Appendix C provides a monthly record of the CRBF for 2007 along with a flow diagram showing the relationships between the FTR auction outcomes and settlements of the day-ahead and real-time energy markets and monthly FTR settlements.

7.4 Financial Transmission Rights Auction Results for 2007

The results for the annual and monthly 2007 FTR auctions and ARR allocation results are discussed below.

7.4.1 Auction Results

The annual auction for FTRs covering the 2007 calendar year was held in December 2006 and offered 50% of the system's transmission capacity. In addition, FTR auctions were held for each month in 2007. In each of these auctions, the remaining balance, up to 95% of the transmission system capacity accounting for expected transmission outages within that month, was made available. The number of participants bidding in each auction ranged from 36 participants in the January 2007 monthly auction to 43 participants in the February 2007 auction. The auction revenues from the 12 monthly auctions and the single 12-month auction covering 2007 totaled $113 million. This represents the participants' risk-adjusted expectation of congestion costs for the system.

Figure 7-2 shows the awarded on-peak FTR megawatts and auction revenues for the annual auctions held in 2005, 2006, and 2007. Relative to 2005 and 2007, 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.[119] The amount of annual on-peak awarded megawatts increased between 2006 and 2007. The increase is due to the combined effect of new participants to the annual auction for on-peak FTRs and increased participation by entities that acquired on-peak FTRs in the 2006 auction.

[119] 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.

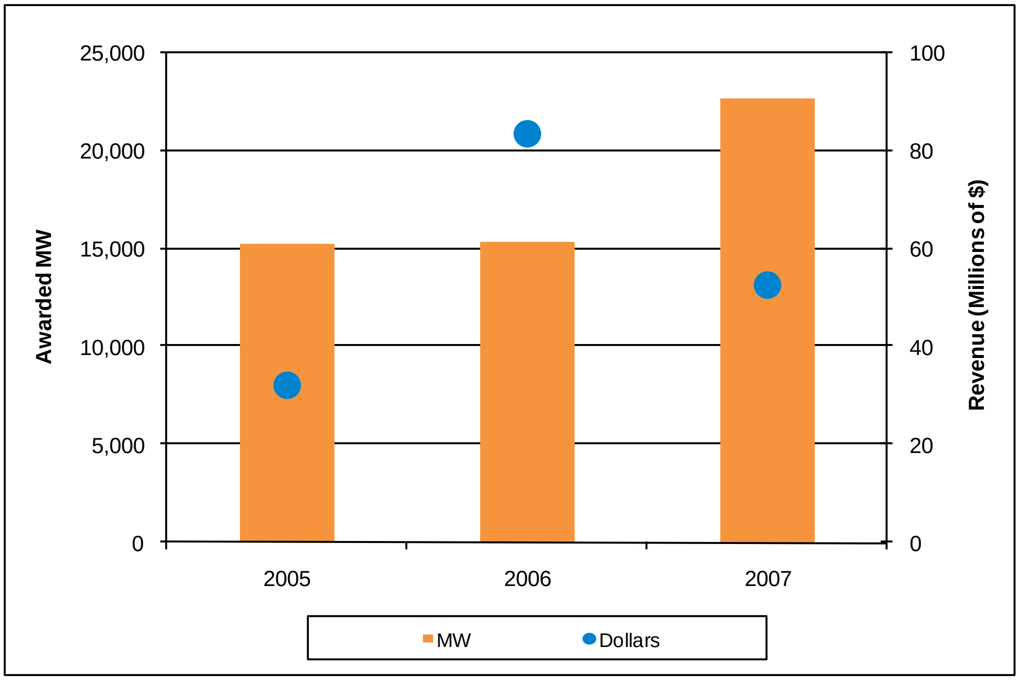

Figure 7-2: On-peak FTR annual auction results.

Figure 7-3 shows the total cleared on-peak auction revenues from the monthly auctions. Revenues in 2005 showed a different pattern than those in 2006 and 2007. In all years, auction revenues peak during the summer when the likelihood of congestion is highest. FTR revenues in the shoulder months of 2004 and 2006 showed similar patterns, whereas in 2005, a second peak in FTR revenues occurred during the fall. This is attributed to expectations of high prices due to upward price pressure on input fuels as a result of hurricanes Katrina and Rita.

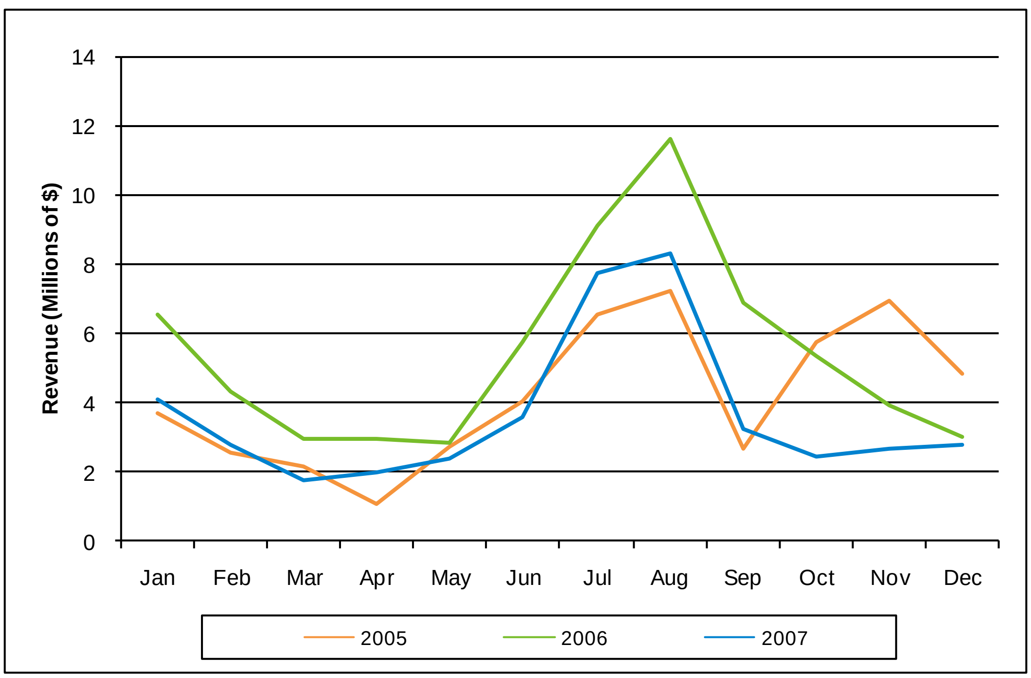

Figure 7-3: Monthly cleared on-peak FTR auction revenues.

Figure 7-4 shows the total cleared on-peak FTRs by month. During the second half of 2007, the total FTR megawatts awarded in the monthly auction generally increased relative to 2005 and 2006. The sum of monthly and annual FTR quantities for any month can exceed the sum of the system's interface limits because of counterflow FTRs.

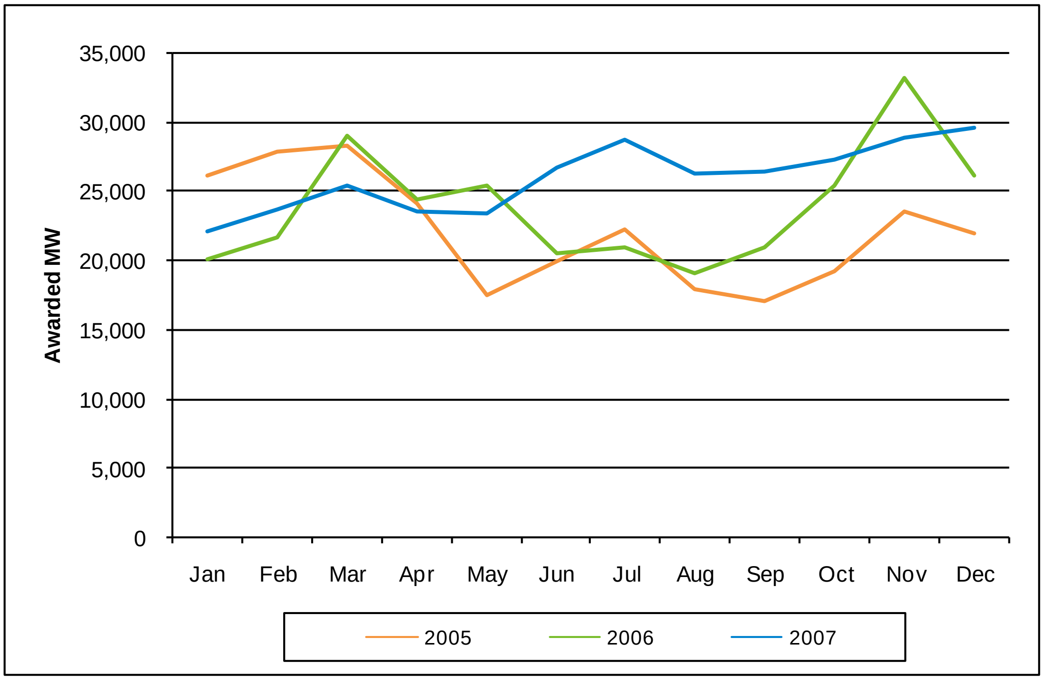

Figure 7-4: Monthly cleared on-peak FTRs, MW.

7.4.2 Financial Transmission Rights Auction Revenue Allocation Results

Table 7-1 shows total distribution of auction revenue for 2004 through 2007 for QUA awards and the three ARR categories. The largest portion of auction revenue was returned to those entities in the load-share category that paid for congestion on the system.

Table 7-1
Total Auction Revenue Distribution, 2004 through 2007, $

Type of Revenue	2004	2005	2006	2007
QUA dollars	3,080,554	1,624,928	3,029,487	3,343,390
Excepted transaction dollars	130,445	260,935	278,913	267,209
NEMA contract dollars	2,859,480	4,592,240	5,215,541	465,603
Load-share dollars	85,630,838	100,712,872	176,471,802	118,735,550
Total auction revenue	**91,701,317**	**107,190,974**	**184,995,743**	**122,811,752**

Figure 7-5 shows the distribution of ARR dollars (load share, NEMA contract, and excepted transactions) by load zone, as defined by the Market Rule 1 allocation process. In 2007, 65% of the ARR dollars were returned to congestion-paying entities in the Connecticut load zone. The SEMA and NEMA load zones each received about 8% of the total, with WCMA receiving 7%. The remaining 10% was distributed among the VT, NH, RI, and ME load zones.

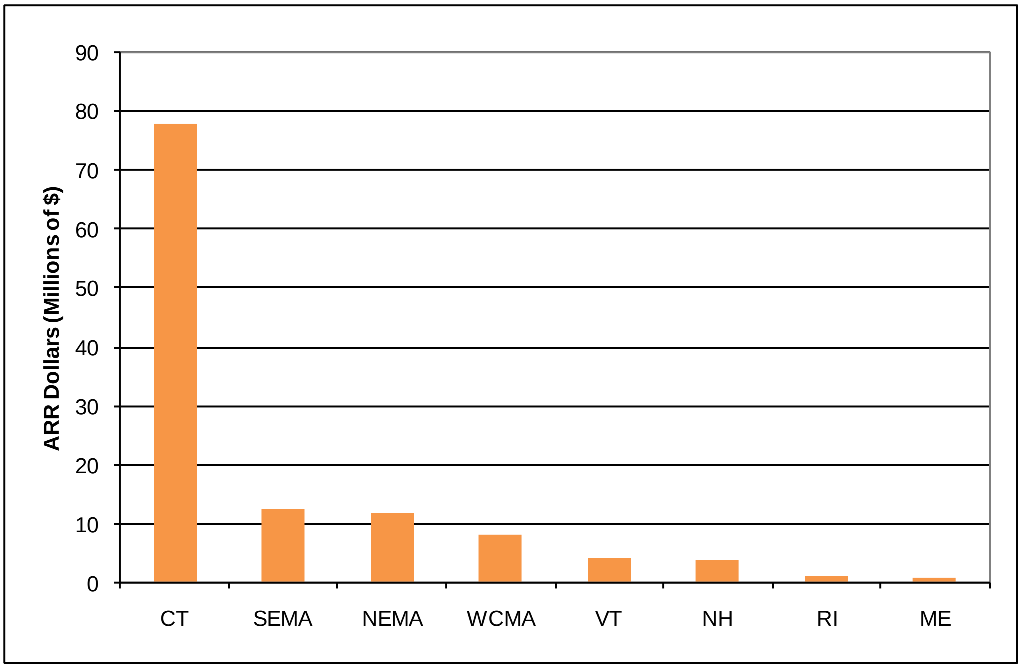

Figure 7-5: ARR distribution by load zone, 2007.

7.5 Collateral Costs and Default Risk

The FTR represents a financial obligation that lasts up to one year. Over time, the congestion pattern may result in an FTR obligation costing the FTR holder more than anticipated. For example, a normally congested path from a generator to a load node may experience unexpected congestion in the opposite direction (from the load to the generator). This would obligate the FTR holder to pay rather than receive congestion revenues, in addition to paying for the FTR in the auction settlement. Because the transmission congestion cost components of LMPs are potentially volatile, the money at risk can be substantial enough to cause defaults.

The risk of default is minimized when an FTR is completely hedged by pairing it with an energy transaction settled in the Day-Ahead Energy Market, as described in Section 7.2.1. In such examples, the energy settlement and FTR settlement transactions offset each other. The net effect is that the LSE prepays the congestion components at the auction price, while the FTR settlement cancels out the congestion component settlement of the energy market transaction, regardless of the direction of congestion in the Day-Ahead Energy Market. Currently, the ISO markets do not have energy markets that match the term of the FTR markets or information on longer-term bilateral transactions that would allow participants to demonstrate their lower default risk resulting from longer-term energy transactions.

Beginning in December 2007, PJM Interconnection encountered several FTR payment defaults.[120] At the time of PJM's filing, four participants had defaulted on margin calls and payment obligations with forecasted default exposure at an estimated $87 million.[121] Such default risks fundamentally create a moral hazard problem because every FTR represents a potential financial obligation that the holder can escape under unfavorable circumstances, leaving other participants to bear the consequences of its untenable FTR positions.[122] FTRs expose their holders to the risk of almost unlimited losses regardless of whether the path cleared the auction as a prevailing or counterflow FTR. This risk further increases as the term of the FTR lengthens because of the probability of unexpected congestion patterns. The risk of default is greatest among pure financial arbitragers without day-ahead energy transactions. The ISO recognizes that these arbitrage-focused participants provide additional liquidity to the FTR market. An evaluation of the liquidity benefits of arbitrage FTRs is an advanced economic topic not covered in this report.

The parent company of the participant that defaulted in the PJM FTR market has four affiliates that participate in the ISO New England markets. The Internal Market Monitoring Unit has reviewed the bid behavior of these affiliates and did not find any behavior that called for action. This includes the regular monitoring of participants' combined activities in the FTR markets and virtual transactions. The ISO is working with NEPOOL participants through an FTR credit working group, organized under the NEPOOL Budget and Finance Committee, to develop changes necessary to minimize exposure to payment defaults that result from FTR market participation. The discussions will focus on improving the financial-assurance policy to better manage the ISO's FTR risk exposure and may include market design revisions.

7.6 Financial Transmission Rights Performance Metrics and Data for 2007

Because FTRs can be treated as both a financial arbitrage tool and a hedging mechanism, two separate performance metrics that explicitly recognize the dual nature of FTRs are appropriate. One measure, the average difference between the auction price and the subsequent payments, examines whether the FTR markets appear to be competitive. If the average difference is close to $0, the market is presumed to be competitive. A large difference could indicate either a lack of competition or a large risk premium. The second measure examines how well FTRs function in providing participants with hedges against congestion charges; hedging is deemed to function well when FTRs are fully funded (100% of the positive target allocation is paid to the FTR holder). The degree of positive target allocation payments represents the extent to which the FTR provides congestion cost certainty. Some participants use both functions of the FTR tool, while others limit their involvement in the FTR market by either hedging the congestion cost of expected physical energy transactions or using FTRs exclusively as an arbitrage instrument.

[120] PJM Interconnection, L.L.C., FERC Docket No. ER08-376 (2007).

[121] PJM Interconnection, *PJM Completes Analysis of Recent Market Payment Default and Announces Steps to Mitigate Future Risk Exposure*, press release (December 26, 2007). Available online at http://www.pjm.com/contributions/news-releases/2007/20071226-credit-default-news-release.pdf.

[122] The moral hazard created by the potential financial obligation can be avoided by using the flow-based transmission pricing methodology as referenced in FERC Order 888. Docket No. RM95-8 (April 24, 1996). See H. Chao and S. Peck. "A Market Mechanism for Electric Power Transmission." *Journal of Regulatory Economics* (1996), and H. Chao, S. Peck, S. Oren, and R. Wilson. *Electricity Journal* (2000) for a description of the methodology.

7.6.1 Financial Instrument Performance Metrics

The appropriate metric for FTR market competitiveness as an arbitrage instrument is the path profitability of FTRs. This profitability is defined as the difference between the cost of acquiring the FTR (auction cost) and the revenue generated by the FTR, which is based on the differences between the day-ahead congestion components. Like in 2006, the FTR auction revenue ($123 million) was close to the day-ahead congestion revenue ($130 million) in 2007.

Figure 7-6 and Figure 7-7 show the percentage of FTR paths by net profit levels for 2007.[123] 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 50 cents. The grayed sections highlight the 41 columns that make up the range of a loss of $1.00/MWh to a profit of $1.00/MWh. The figures demonstrate that almost all FTRs have monthly profit levels within ±$1.00/MWh. The average monthly profit is 5 cents/MWh for an on-peak FTR and 1 cent/MWh for an off-peak FTR. Like in 2006, the FTR auction revenue was only slightly higher than the congestion revenue in 2007. These results are consistent with a competitive market in which the expected profits of a risk-neutral participant holding an FTR as an arbitrage instrument should approach $0.

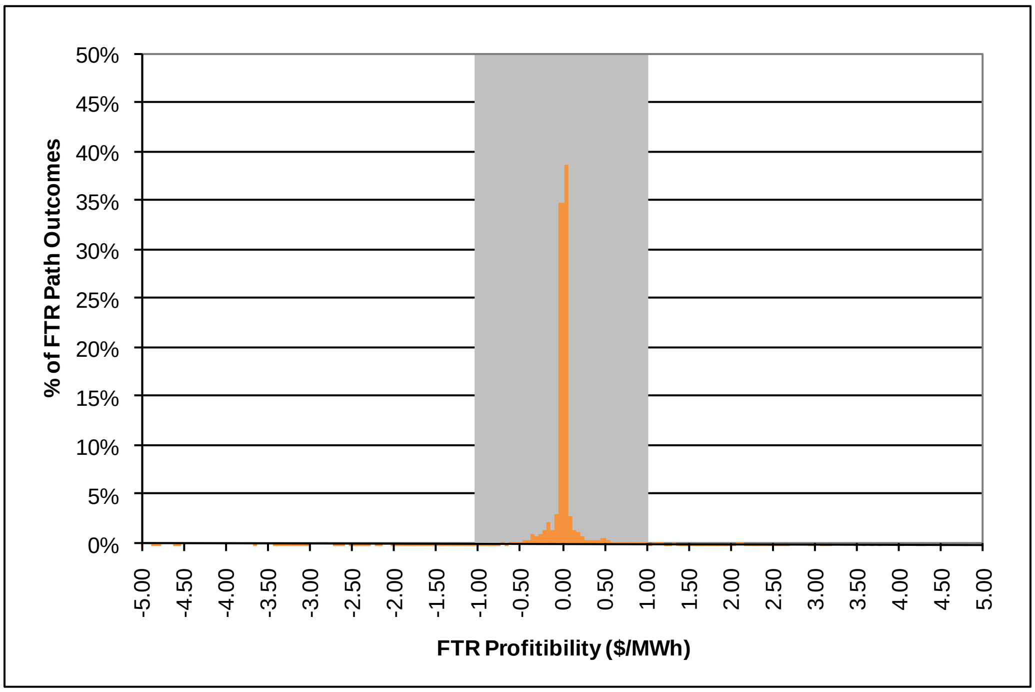

Figure 7-6: Percent of off-peak FTR path profit for 2007 by 50-cent profit bins.

Note: The horizontal axis is truncated at profit bins of ±$5. The largest loss was $5.08/MWh, and the largest profit was $5.55/MWh.

[123] These profit levels are based on the monthly settlements, which include prorated discounting of positive target allocations during months with revenue shortfalls. Revenues from the end-of-year redistribution of the annual Congestion Revenue Balancing Fund are not included.

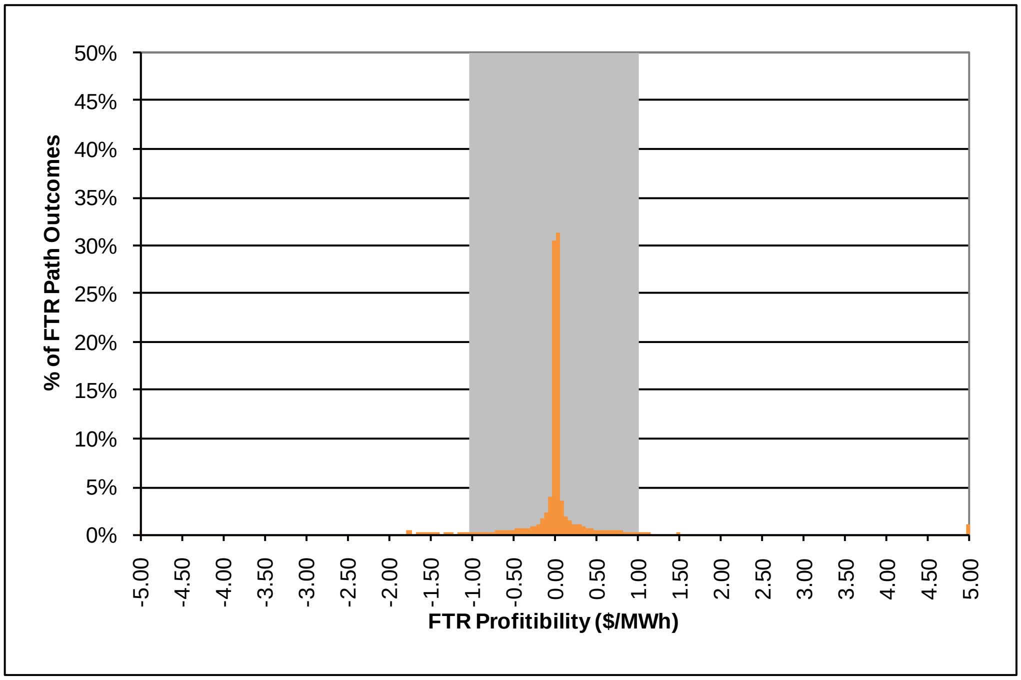

Figure 7-7: Percent of on-peak FTR path profit for 2007 by 50-cent profit bins.

Note: The horizontal axis is truncated at profit bins of ±$5. The largest loss was $18.06/MWh, and the largest profit was $21.82/MWh.

7.6.2 Performance Metric for Hedging Day-Ahead Congestion Costs

Participants that purchase FTRs to hedge the day-ahead congestion costs of expected future energy transactions place a value on this certainty, which is defined by the participant's willingness to pay for the FTR in the auction.[124] A risk-neutral participant would bid an amount equal to their expectation of the future congestion costs, while risk-averse participants would be willing to pay an amount in excess of expected congestion costs to obtain price certainty. 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.

By offsetting the congestion costs of a day-ahead position between two points on the system, a fully funded FTR provides an effective hedge of the day-ahead congestion costs. FTRs used in combination with participation in the Day-Ahead Energy Market (either directly or as a mechanism to settle bilateral agreements) allow participants to hedge against the price volatility of the Real-Time Energy Market.[125]

For fully funded FTRs, the ISO pays out 100% of the positive target allocations associated with FTRs, and the FTR provides the expected congestion cost hedge. If the amount of revenue in the monthly Congestion Revenue Balancing Fund is insufficient to pay out 100% of the systemwide positive target allocations, all FTR payouts are prorated.

[124] The net value a participant places on its portfolio of FTRs would be based on both its bids for FTRs in the auctions and its share of ARR.

[125] Day-ahead or bilateral positions allow hedging of the energy and congestion components of the real-time LMP; however, the ISO does not provide a tool to hedge marginal loss costs in either the Day-Ahead or Real-Time Energy Markets.

Table 7-2 summarizes the monthly Congestion Revenue Balancing Fund for 2007, including the monthly percentage of positive target allocations paid to FTR holders.[126] During eight of the 12 months in 2007, FTR holders were not paid their full positive target allocation.[127]

Table 7-2
Transmission Congestion Revenue Balancing Fund, 2007, $

Month	Day-Ahead Congestion Revenue	Real-Time Congestion Revenue[(a)]	Negative Allocation Collected (Paid by Participants)	Positive Target Allocation (Owed to Participants)	Actual Positive Allocations Paid to Participants	Monthly Fund Surplus or Shortfall	Percent of Positive Target Allocation Paid
Jan	9,759,970	–2,938,756	8,567,058	17,113,217	15,432,626	1,680,591	90%
Feb	5,530,448	–1,054,643	3,985,262	9,034,375	8,481,352	–553,023	94%
Mar	12,998,680	–4,401,633	6,570,084	17,522,674	15,177,946	–2,344,728	87%
Apr	8,219,531	–303,743	3,631,264	11,518,292	11,518,292	28,855	100%
May	14,021,210	–222,907	10,064,586	20,434,289	20,434,289	3,429,223	100%
Jun	13,914,953	–1,417,732	7,825,638	18,307,182	18,307,182	2,016,486	100%
Jul	15,562,340	–2,133,607	7,256,242	21,333,474	20,715,021	–618,453	97%
Aug	15,058,856	–3,900,624	5,447,628	19,891,761	16,641,293	–3,250,469	84%
Sep	12,319,271	129,367	4,390,331	19,708,794	16,861,399	–2,847,395	86%
Oct	12,482,899	–1,234,365	5,610,585	22,015,869	16,881,359	–5,134,510	77%
Nov	4,084,168	–401,302	2,225,391	6,129,306	5,926,182	–203,124	97%
Dec	6,193,537	143,349	3,616,337	8,483,939	8,483,939	1,470,283	100%

(a) See Section 2.4.6 for a description of real-time congestion and how it can be a negative value.

Figure 7-8 shows the percent of positive target allocation paid to FTR holders per month for the extended period of January 2005 to December 2007. During several months in each of the three years, participants received less than 100% of their positive target allocations. Monthly shortfalls in the Congestion Revenue Balancing Fund are a result of two types of differences in outage assumptions or transfer limits between the different markets associated with the FTR settlement process. These include (1) differences between the FTR auction and the Day-Ahead Energy Market, and (2) differences between the Day-Ahead Energy Market and real-time operations.

[126] Appendix B shows more details about Congestion Revenue Fund accounting.

[127] Participants' FTR portfolios for a particular month are settled on the basis of that month's congestion components. A portfolio can be composed of both annual and monthly FTRs.

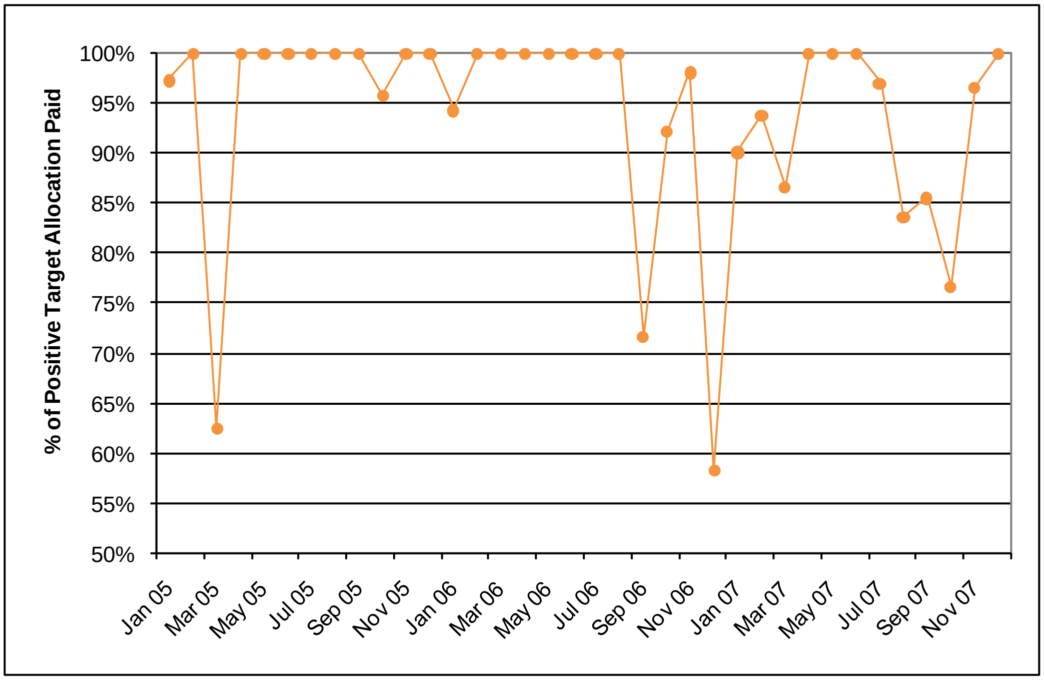

Figure 7-8: Percentage of positive target allocations paid out per month from January 2005 to December 2007.

Note: These percentages represent only the monthly settlement amounts.

Figure 7-9 shows the monthly surplus and shortfall levels for the three years ending December 2007. The months with surpluses in 2005 and 2006 were sufficient to compensate FTR holders for their monthly shortfalls plus interest at the end-of-year settlements. During these years, FTRs provided the desired congestion cost hedge to participants that acquired them for that purpose. For the year 2007, the surpluses in April, May, June, and December were not sufficient to compensate for the monthly shortfalls plus interest owed to FTR holders. Therefore, for 2007, FTRs did not compensate FTR holders for 100% of the positive allocations derived from day-ahead congestion costs. Of the $191.8 million of total positive target allocations (plus interest accrued on shortfalls owed to holders of FTRs), $182.0 million, or 95%, were eventually paid out.

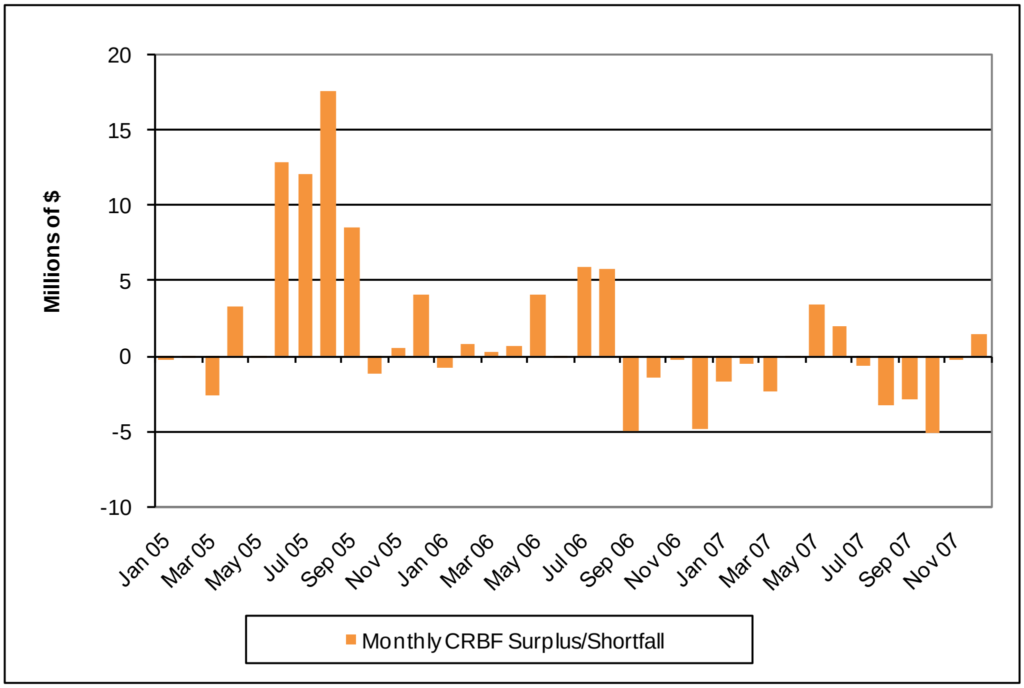

Figure 7-9: Monthly Congestion Revenue Balancing Fund surplus and shortfall levels.
Note: These percentages represent only the monthly settlement amounts.

Figure 7-10 compares the sum of day-ahead congestion revenue and negative target allocations (the columns) with the monthly level of positive target allocation (the black tick mark) for each month. During most months since January 2005, the sum of day-ahead congestion and negative target allocations exceeded the positive target allocations. This indicates that outage assumptions and transfer limits used in the FTR auctions generally are adequate, so that the ISO does not consistently award more megawatts than can be supported by the day-ahead congestion costs. Based on these outcomes, most of the monthly shortfalls are attributable to differences between the Day-Ahead Energy Market and real-time operations. This is confirmed by Figure 7-11, which compares the sum of monthly net congestion revenue (the sum of day-ahead and real-time congestion revenue) plus negative allocations with monthly positive target allocations. Portions of the net congestion column below the zero line represent negative real-time congestion. The months with horizontal tick marks above the columns, which represent positive target allocations, had a revenue shortfall.

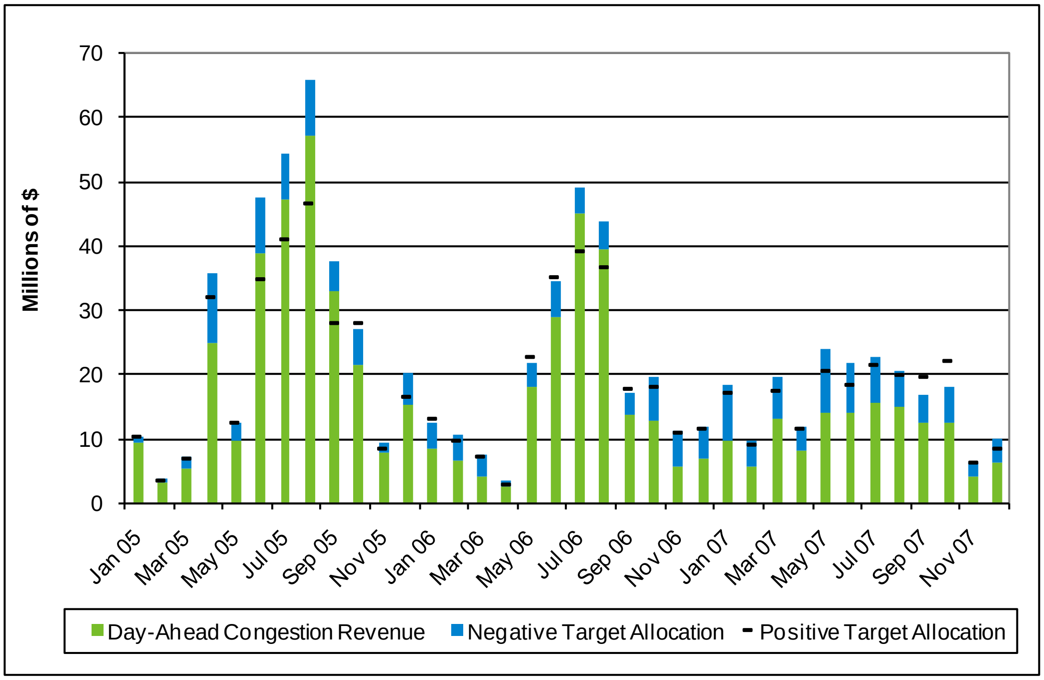

Figure 7-10: Monthly day-ahead revenue sources in relation to positive target allocation amounts.

Note: The tick marks represent the level of the monthly positive target allocation. If the mark is above the column, day-ahead revenue sources are less than positive target allocations. If the tick mark is below the column, day-ahead revenues are greater than positive target allocations.

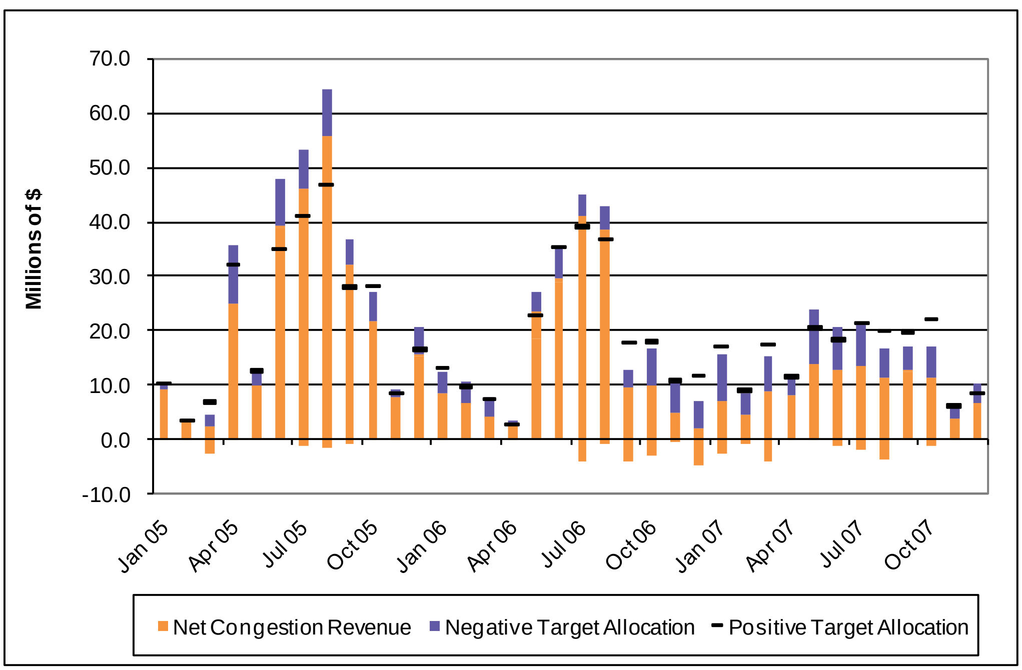

Figure 7-11: Monthly revenue sources and positive target allocation amounts.

Note: The tick marks represent the level of monthly positive target allocations. If the mark is above the column, the CRBF is in shortfall for the month. If the tick mark is below the column, the CRBF has a surplus for that month.

A closer look at real-time congestion revenue in Figure 7-12 shows the variation of monthly average levels over time and the trend of the 12-month rolling average that has become increasingly negative over the past few years.

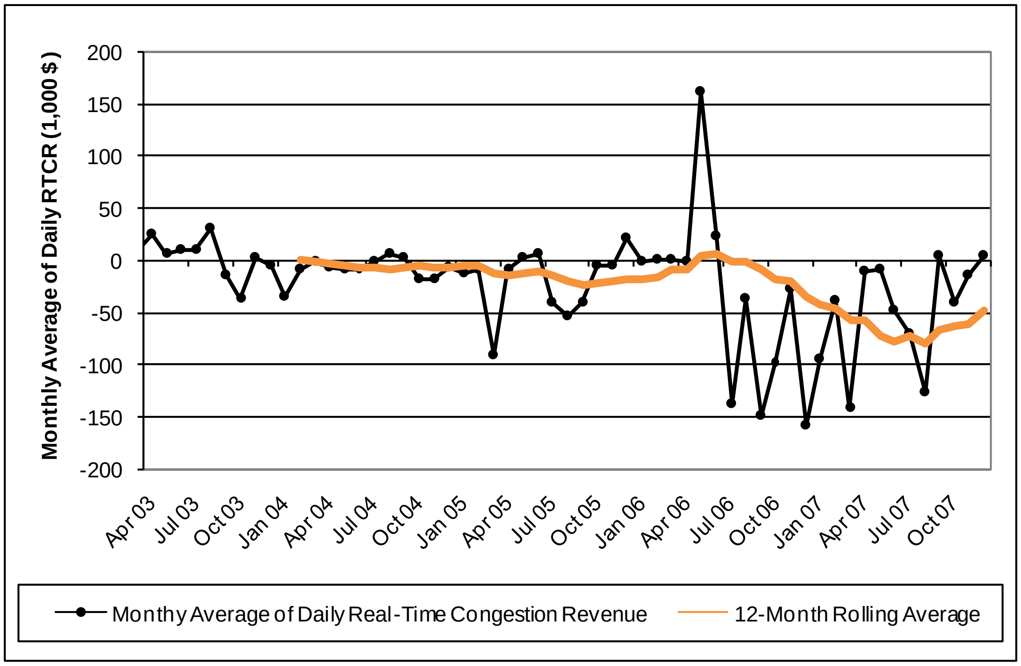

Figure 7-12: Historical monthly real-time congestion revenue.

7.7 Financial Transmission Rights Conclusions

The annual and monthly FTR auctions conducted in 2007 were basically competitive, generating a total of $123 million in auction revenues. This revenue was distributed back to congestion-paying LSEs and transmission customers that support the transmission system. The majority of the revenue was distributed as auction revenue rights to entities in Connecticut. The financial transmission rights that were auctioned served two distinct functions—as a financial instrument and a hedging instrument—whose performance was evaluated separately.

As a financial instrument, FTRs are being valued efficiently in auctions, which results in path profit levels that approach zero on average. This is consistent with the outcome of a competitive market. In their second function as a hedging instrument for congestion costs, FTRs did not perform as well during 2007 compared with previous years. During eight of the 12 months of 2007, FTRs did not provide a full hedge against the transmission congestion costs in day-ahead energy transactions. Further, the year-end cumulative balance was not sufficient to meet the monthly shortfalls, resulting in a partial hedge of 95% at the annual level. An analysis of the monthly shortfalls for 2007 indicates that negative real-time congestion is the most frequent cause of these shortfalls.

Differences in the outage assumptions or transfer limits used by the Day-Ahead Energy Market and real-time operation are a primary cause of negative real-time congestion. These differences can be caused by unexpected transmission or generation outages or unexpected load patterns. The monthly shortfalls adversely affect the ability to pay 100% of positive target allocations. To improve the hedging value of FTRs, the ISO continually monitors the balance of the CRBF and identifies the conditions that contribute to surpluses and shortfalls.

The ISO has taken two actions that should lessen any shortfalls in the future. First, the ISO has changed Operating Procedure 3 (OP 3), *Transmission Outage Scheduling*, to enhance the coordination between FTR scheduling and outage planning.[128] Second, the ISO has begun developing advanced applications for interface-limit calculations that will promote a more consistent application of interface limits across FTRs and the Day-Ahead and Real-Time Energy Markets, thus improving the effectiveness of the FTR hedge.

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

Section 8
Demand Resources

In the New England Control Area, *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. Such resources may include individual measures at individual customer facilities or a portfolio of measures implemented by many customer facilities and aggregated together as a single resource. *Demand response* is a specific type of demand resource in which electricity consumers modify their electric energy consumption in response to incentives based on wholesale market prices. *Other demand resources* (ODRs), such as energy efficiency, load management, and distributed generation, 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 serve as reserve capacity, or they may promote more economically efficient uses of electrical energy. Along with adequate supply and robust transmission infrastructure, demand resources are an important component of a well-functioning wholesale market.

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 progress of demand-resource programs can be measured in terms of both their depth and breadth. Depth of market penetration is represented by the number of enrollments in a program. Breadth is represented by the mix of market products and programs in which customers can elect to participate. As the mix of programs improves, more customers will enroll. In particular, customers with lower costs should be able to find programs that correctly price their lower-cost service.

Demand resources made great strides in 2007 with the advent of the Forward Capacity Market in which these resources can compete for capacity credits and capacity transition payments similar to supply-side resources. Average enrollment in the ISO’s demand-response programs increased approximately 103% from 2006 to 2007, and 2,521 MW of new demand resources qualified for the Forward Capacity Auction. This section describes the ISO’s demand-side initiatives, discusses the results of these efforts, and summarizes the performance of demand resources.

8.1 ISO New England Demand Resources

ISO New England’s demand resources have evolved over the past few years. At the start of Standard Market Design in 2003, the ISO had four real-time demand-response programs comprised of three reliability programs and a single real-time price response program. The Day-Ahead Load-Response

Program was added in 2004, allowing any resource enrolled in one of the four real-time demand-response programs an opportunity to commit curtailments based on day-ahead LMPs. During 2007, the ISO operated 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. ODRs came into being with the implementation of the FCM transition period. The reliability-activated demand-response programs and ODRs are considered capacity resources and are eligible to receive capacity transition payments (see Section 3.5).

8.1.1 Reliability Programs

The reliability-based real-time demand-response programs 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 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 4.1).

The reliability programs are available at certain steps during the ISO's prescribed OP 4 actions during a capacity deficiency.[129] The OP 4 guidelines contain 16 actions that can be implemented individually or in groups depending on the severity of the situation. 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. (Refer to Section 2.5 for more information on OP 4 events.)

8.1.2 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

[129] OP 4 is available online at http://www.iso-ne.com/rules_proceds/operating/isone/op4/.

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.

8.1.3 Other Demand Resources

ODRs were established by the FCM Settlement Agreement and are eligible to receive capacity transition payments. These resources consist of energy efficiency, load management, and distributed generation projects implemented by market participants at retail customer facilities:

- **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 implements a lighting upgrade in a factory, replacing 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 current 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 consists 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.

Other demand resources 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.

Figure 8-1 summarizes the installed capacity performance of ODRs throughout 2007. The ODRs are compensated only for capacity because their energy value is presumed to be compensated by avoiding energy consumption and associated retail energy charges. As such, all values are reported in megawatts rather than in megawatt-hours. As Figure 8-1 shows, most monthly ODR capacity comes from energy-efficiency projects.

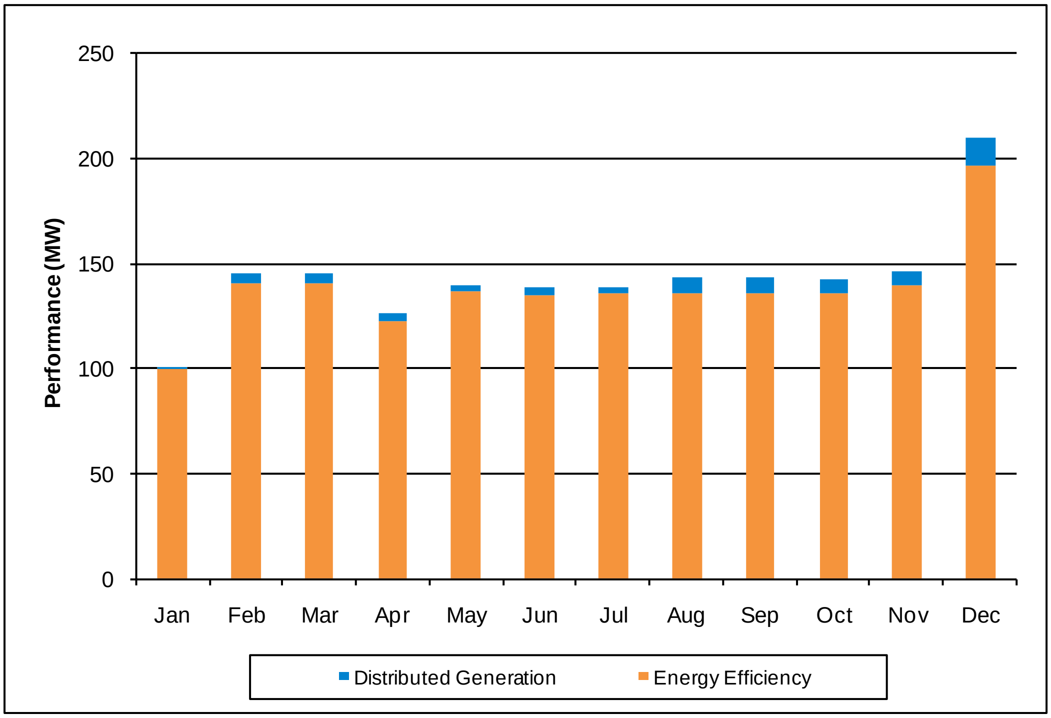

Figure 8-1: Monthly ICAP ODRs by resource type, 2007.

8.2 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).[130] The stated goal of the RFP was to improve the reliability of the bulk electric power system in Southwest Connecticut. The majority of the resources selected under this RFP are participating in the 30-Minute Real-Time Demand-Response Program. These resources receive supplemental capacity payments expected to total $128 million over the four-year contract term. As of December 1, 2007, program payments have totaled over $115 million. Contracts with resource providers pursuant to the SWCT Gap RFP are expected to expire after May 31, 2008. The 2007 monthly average enrollment for the SWCT Gap RFP was 184 MW. The summer peak-month (June to August) average enrollment was 207 MW.

8.3 Demand-Resource Program Participation

The number of megawatts participating in ISO markets as a demand resource has seen a large increase during the last three years. Average annual enrollment in 2007 in all demand-resource programs, including demand-response programs and ODR projects, increased approximately 103%, from an annual monthly average of 650 MW in 2006 to 1,324 MW in 2007. The total increase

[130] 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 online at http://www.iso-ne.com/genrtion_resrcs/reports/rmr/swct_gap_rfp_fnl_rpt_10-05-04.doc.

between January 2005 and December 2007 has been 430%. Figure 8-2 shows demand response and ODR program enrollments by month for 2005 through 2007.

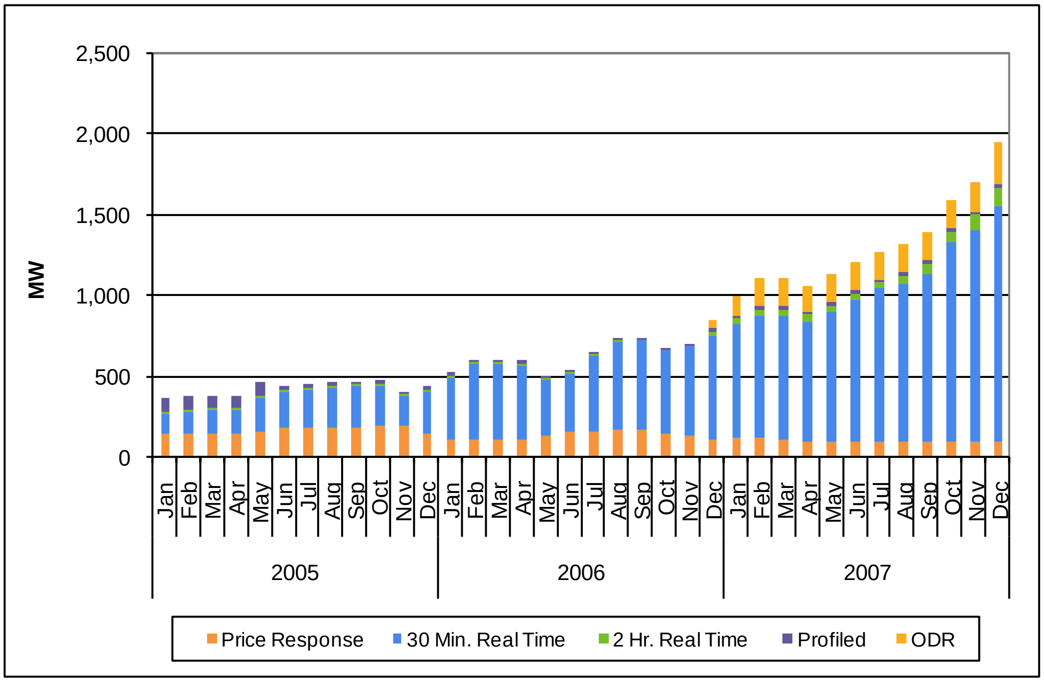

Figure 8-2: Monthly demand resource enrollments, 2005 through 2007.

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 can anticipate fewer hours of interruptions. Currently, 64.7% of the customers in this program have elected Action 12.

Table 8-1 shows a regional breakdown of demand-response assets and megawatts of participation during December 2007 and the percentage change from system totals for December 2006.

Table 8-1
Demand-Response Assets, December 2007

Zone	December 2007					
	# of Assets	Total MW	Real-Time Price Response (MW)	Real-Time 30-Min Demand Response (MW)	Real-Time 2-Hour Demand Response (MW)	Profiled Demand Response (MW)
Rest of CT	672.0	377.4	6.6	370.8	-	-
SWCT	674.0	364.7	0.7	364.0	-	-
ME	52.0	405.0	-	318.4	75.6	11.0
NEMA	298.0	147.4	31.0	116.4	-	-
NH	71.0	74.7	4.5	68.5	1.7	-
RI	195.0	76.4	16.5	54.9	5.0	-
SEMA	240.0	64.6	10.6	50.4	3.6	-
VT	57.0	62.6	6.3	39.1	11.3	5.9
WCMA	289.0	121.1	21.9	80.0	19.2	-
Total	**2,548.0**	**1,693.7**	**98.0**	**1,462.5**	**116.3**	**16.9**
% Change from 2006	**71%**	**111%**	**-17%**	**128%**	**343%**	**0%**

Table 8-2 calculates the zonal increases in demand response from December 2006 to December 2007. Participation increased across all zones throughout the course of the year. 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, 254 MW or 28% of the total 2007 increase. As Table 8-1 shows, Maine has 405 MW, or 23%, of the 1,693.7 MW total.

Table 8-2
Zonal Increase in Demand Response, December 2006 to December 2007

Zone	Change 2006 to 2007					
	Assets	Total MW	Real-Time Price	Real-Time 30-Min	Real-Time 2-Hour	Profiled
Rest of CT	296.0	143.7	–7.5	151.2	0.0	0.0
SWCT	221.0	139.3	–0.2	139.5	0.0	0.0
ME	32.0	254.2	0.0	193.6	60.6	0.0
NEMA	129.0	86.8	1.0	85.8	0.0	0.0
NH	59.0	57.9	–11.3	67.5	1.7	0.0
RI	51.0	57.6	–1.4	54.0	5.0	0.0
SEMA	117.0	42.0	–0.9	39.3	3.6	0.0
VT	29.0	32.3	–1.3	32.3	1.3	0.0
WCMA	124.0	78.5	2.2	58.4	17.9	0.0
Total	**1,058.0**	**892.3**	**–19.4**	**821.6**	**90.1**	**0.0**

Increased capacity transition payments are the most likely explanation for the very sizable increase in demand-response program participation over the past year. The reliability programs qualify as capacity and thus are eligible for the capacity transition payments under current program rules. The increase coincides with the timing of the capacity transition payments, which began in December 2006. The FCM settlement established the transition payment rate at $3.05/kW-month. Before the capacity transition payments, capacity payments through the ICAP supply auction prices averaged $0.205/kW-month.[131]

All the increased demand-resource participation has been in the reliability programs and as ODRs. As Figure 8-2 shows, only the price-response program had a decline in enrollment. This pattern of change further supports the conclusion that the increase in demand-response participation was largely attributable to the introduction of capacity transition payments.

8.4 Demand-Response Interruptions

Table 8-3 shows the results of all demand-response programs combined, including interruptions resulting from ISO event activations (reliability events and real-time price-response program events) and from participation in the Day-Ahead Load-Response Program. In total, the program measured 235,345 MWh of interruptions during the year. In 2007, load interruptions took place on 256 days due to at least one demand-response program.

Table 8-3
Summary of 2007 Results for All Demand-Response Programs

Month	Number of Days with Interruptions	MWh Interrupted	Payment ($)
Jan	22	14,099	$1,030,624
Feb	20	21,415	$1,817,996
Mar	22	14,768	$1,124,263
Apr	21	6,959	$583,723
May	22	9,581	$726,414
Jun	21	13,807	$905,690
Jul	21	19,352	$1,400,718
Aug	23	34,269	$3,573,945
Sep	19	26,201	$2,059,052
Oct	23	23,024	$1,633,525
Nov	20	19,049	$1,318,548
Dec	22	32,821	$3,471,416
Total	**256**	**235,345**	**$19,645,914**

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

Load interruptions can be caused either by the activation of an ISO-initiated event or by participation in the Day-Ahead Load-Response Program, which obligates resources to interrupt load in real time if a participant's day-ahead load interruption offer is accepted. As described in Section 9.1.1 and Section 9.1.2, 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. Table 8-4 lists the number of interruptions by program type. The interruptions are dominated by the Real-Time Price-Response Program and the Day-Ahead Load-Response Program, which registered 229 and 249 days of interruptions, respectively, in 2007. The reasons for the high frequency of interruptions are described in more detail in Section 8.4.1 and Section 8.4.2. The 30-Minute and Two-Hour Real-Time Demand-Response Programs and the Profiled Program were activated on a total of two days in 2007. Both of these activations took place in Maine on December 1 and 2 when OP 4 Actions 3 and 9 were declared. However, since these activations occurred on a weekend, outside program hours, response by program participants was voluntary.

Table 8-4
Number of Interruption Days in 2007

Demand-Response Program	Number of Days with Interruptions
Real-Time 30-Minute Program	2
Real-Time Two-Hour Program	2
Real-Time Profiled Program	2
Real-Time Price-Response Program	229
Day-Ahead Load-Response Program	249

In contrast, the Real-Time Price-Response Program was activated a total of 229 days out of a possible total of 254 workdays. Also, participation in the DALRP was frequent, which resulted in real-time interruptions on 249 days. Therefore, days with interruptions are almost entirely due to the Real-Time Price-Response Program and the DALRP.

8.4.1 Analysis of Day-Ahead Load-Response Program Interruptions

Table 8-5 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.[132] In the table, real-time deviations from the day-ahead cleared quantities ("Day-Ahead Cleared") are counted as part of real-time interruptions ("Actual Day-Ahead Program Interruptions").

[132] Recall that 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 8-5
Day-Ahead Load-Response Program Interruptions and Payments, 2007

	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	730.5	13,022.4	923,841.31	22.7	110.4	7,503.26
Feb	2,481.1	19,607.6	1,632,109.56	13.2	35.6	3,460.42
Mar	2,191.2	13,135.4	959,886.15			
Apr	37.4	4,785.7	365,191.09			
May	616.0	8,994.9	659,497.00			
Jun	259.6	10,944.8	814,967.23			
Jul	1,602.9	19,792.5	1,457,715.15	18.5	46.3	3,264.16
Aug	6,718.5	32,480.1	2,539,078.16	42.6	232.3	16,387.57
Sep	5,032.3	25,732.9	1,989,571.67	41.7	70.1	5,045.61
Oct	6,290.9	22,178.8	1,554,105.71	48.4	202.6	14,277.70
Nov	5,163.2	17,569.5	1,177,618.93	38.5	283.6	19,129.44
Dec	7,792.4	29,635.7	2,882,882.48	44.0	300.1	28,645.39
Total	**38,916.0**	**217,880.2**	**16,956,464.40**	**269.6**	**1,280.9**	**69,068.16**

(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] x day-ahead LMP

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

As an example to illustrate how the quantities in Table 8-5 were calculated, a load resource has a customer baseline (CB) (i.e., the measurement of the customer's expected consumption absent a load-response event) of 3 MW and clears 1 MWh in the day-ahead process. In real time, the customer consumes 0 MWh (as indicated by the customer's interval meter). Accordingly, the customer has a 2 MWh deviation. This 2 MWh deviation is counted as an additional interruption above the required amount of 1 MWh, which cleared in the DALRP. In Table 8-5, this resource will have 1 MWh in the "Day-Ahead Cleared" column and 3 MWh in the "Actual Day-Ahead Program Interruptions" column. The "Day-Ahead Program Payments" column would include the 1 MWh that cleared day ahead multiplied by the day-ahead LMP, plus the additional 2 MWh of interruption multiplied by the real-time LMP.

In the second half of 2007 (August to December), the ISO identified design flaws in the DALRP. The flaws allowed the CB to be frozen at an elevated level, creating the illusion that some DALRP participants were achieving a higher amount of load reduction than they actually were attaining. The CB is intended to represent the current expectation of the customer's true load profile. The ISO's present method for estimating the CB is essentially a rolling 10-day average of a customer's normal load from days without load-response events. Days with load-response events are excluded from the calculation of the asset's customer baseline.[133] Thus, if a customer had a CB of 5 MW on May 12, and a load-response event occurred on May 13, the customer's CB for May 14 would have been the 5 MW CB that was determined on May 12. This is appropriate, for example, in the case of a heat wave that causes load-response events on consecutive days of interruptions.

However, participants placing offers at the minimum offer price of $50/MWh would have cleared 249 out of 254 program days in 2007 (i.e., practically every eligible program day). The vast majority of DALRP participants placed offers at the minimum offer price. Because electricity prices have risen with fuel costs, the minimum bid of $50/MWh has become equivalent to the cost of a baseload unit. By submitting the minimum bid of $50/MWh and 100 kWh, a customer can be assured it will clear almost every program day. The combination of the $50/MWh minimum offer price and the ISO's CB method created an opportunity for customers to set a high CB during a peak consumption season and then freeze it by clearing in the day-ahead market every day. This thus created the illusion of high load reduction amounts in off-peak seasons.

When the CB is frozen, determining whether load actually is reduced becomes difficult. Many customers have bids of $50/MWh and 100 kWh (the minimum bid parameters), creating the initial "event" that freezes the CB every day. In real time, any load metered below the CB is counted as an interruption. If the CB is 5 MW and the load meters 4.9 MWh, the load has matched the day-ahead bid of 100 kWh. If the load is 2 MWh, an interruption of 3 MWh is calculated. The surplus interruption of 2.9 MWh is paid at the real-time energy price as a deviation.

Figure 8-3 shows that participation in the DALRP grew during 2007. By December 2007, slightly more than 80 assets on average were offering into the DALRP, compared with just over 10 at the beginning of the year.

[133] ISO New England. *Day-Ahead Load Response Program (DALRP): Recommended Market Rule Changes,* Presentation to the ISO New England Board of Directors Markets Committee (January 23, 2008). Available online at http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/dr_wkgrp/mtrls/2008/jan252008/a2_iso_presentation_01_23_08.ppt.

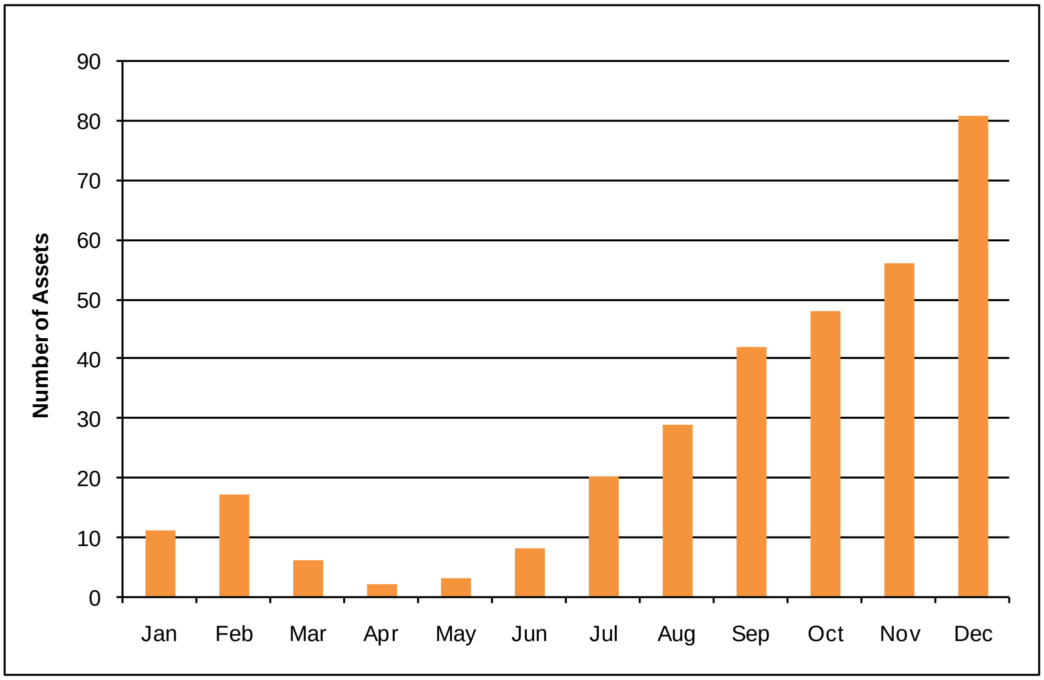

Figure 8-3: Average number of assets offering in the DALRP per month, 2007.

Figure 8-4 compares the demand-response interruptions in 2007 that are attributable to the DALRP with those attributable to the other programs. It further breaks down the DALRP interruptions into "DA Cleared MWh" and "DA Deviation MWh." The day-ahead deviation megawatts outweigh all other sources. The large number of deviations is consistent with frozen CBs that tend to create overstated load reductions.

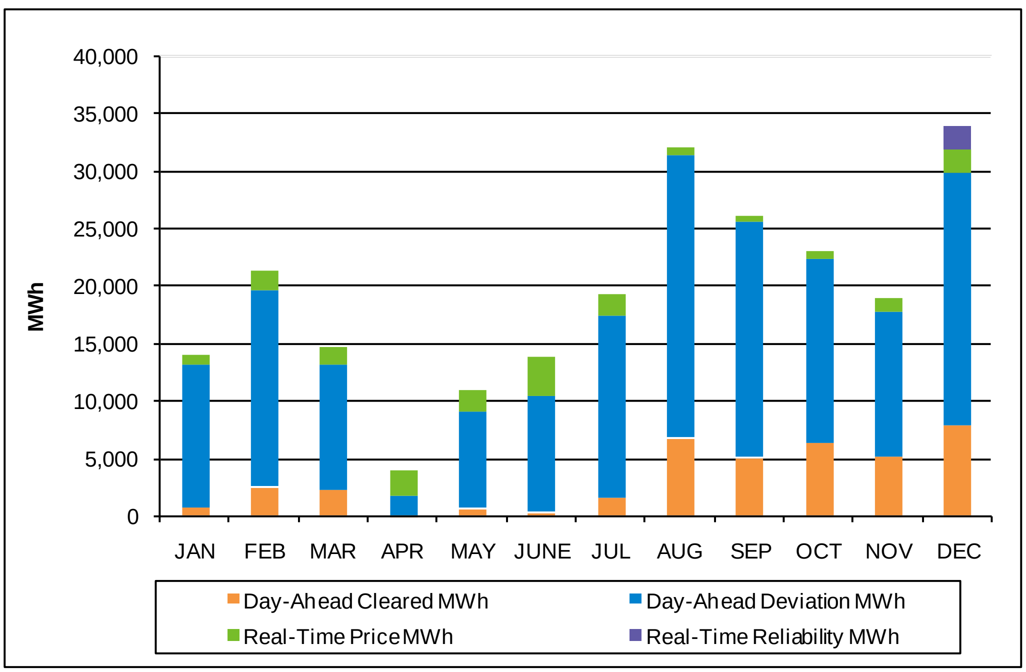

Figure 8-4: Load-reduction program type, MWh

In 2007, 39,185 MWh of demand response cleared in the day-ahead market. This is 18.5% of the total of 211,861 MWh that the DALRP counted as interruptions (the sum over the year of the day-ahead cleared MWh and day-ahead deviation MWh). DALRP payments for deviations amounted to $13.7 million in 2007. Total DALRP payments have grown from about $2.04 million in 2006 to $17 million in 2007. In 2007, over half the payments were made to DALRP participants with static CBs. By December 2007, 73.3% of the demand-response megawatts had static CBs.

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.[134] The ISO's solution was to redefine the minimum bid price as a heat rate multiplied by a monthly fuel index. Using the minimum offer price of $50/MWh and average fuel prices from 2002, the year in which the DALRP originally was designed, an implicit heat rate of 12.92 MMBtu/MWh was derived. In 2002, energy clearing prices were above $50/MWh less than 12 % of the time. The 12.92 MMBtu/MWh was intended to duplicate this percentage going forward. In February 2008, the fuel index had a value of $9.35/MMBtu, yielding a minimum bid price of $121/MWh.

The revised minimum bid price is expected to reduce the frequency that resource bidding at the minimum offer price will clear in the day-ahead load-response process. Once the asset does not clear, its CB will be refreshed with contemporary meter data, thus addressing the static baseline problem.

8.4.2 Real-Time Load-Response Program Interruptions

Table 8-6 shows the interruptions (MWh) and payments associated with the real-time load-response programs in 2007.[135] The Real-Time Price-Response Program experienced the most activity and had a total of 229 days with interruptions. Participation in voluntary price-response program events depends on the electric energy price levels and the business condition for each customer. The Real-Time Price-Response Program resulted in 18,787 MWh of load curtailments in 2007. The number of resources that curtailed load and the total load curtailed varied from event to event.

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

[135] 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 8-6
Real-Time Program Interruptions and Payments, 2007

	Reliability Programs				Price-Response Program	
	Demand Response		Profiled Response			
	Real-Time Program Interruptions (MWh)	Real-Time Program Payments ($)[a]	Real-Time Program Interruptions (MWh)	Real-Time Program Payments ($)[a]	Real-Time Program Interruptions (MWh)	Real-Time Program Payments ($)[a]
Jan	0	0	0.0	0	966.9	99,279
Feb	0	0	0.0	0	1,772.7	182,426
Mar	0	0	0.0	0	1,632.8	164,376
Apr	0	0	0.0	0	2,174.2	218,532
May	0	0	0.0	0	1,899.4	66,917
Jun	0	0	0.0	0	3,367.2	123,486
Jul	0	0	0.0	0	1,968.6	115,611
Aug	0	0	0.0	0	623.6	86,682
Sep	0	0	0.0	0	510.8	59,858
Oct	0	0	0.0	0	643.0	65,141
Nov	0	0	0.0	0	1,195.7	121,799
Dec	2,032	232,637	111.7	14,119	2,032.0	313,131
Total	**2,032**	**232,637**	**111.7**	**14,119**	**18,787.1**	**1,617,243**

(a) The payments equal the MWs x LMPs.

8.4.3 Analysis of Real-Time Price-Response Program Interruptions

Real-time interruptions occurred on practically every nonholiday weekday due to the high frequency with which the Real-Time Price-Response Program is activated. In 2007, the Real-Time Price-Response Program was activated a total of 229 distinct days out of 254 nonholiday weekdays. As previously mentioned, 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 through the Security Constrained Resource Adequacy (SCRA) process. System operators use the SCRA process internally to reliably manage the system. Because price forecasts, not actual real-time prices, activate the Real-Time Price-Response Program, it 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 for 2007 was $69.57/MWh, while the price-response program guarantees a minimum payment of $100/MWh, regardless of the real-time LMP. Figure 8-5 summarizes the distribution of real-time prices during hours with real-time interruptions. The figure shows that the real-time LMP was greater than $100/MWh during only 21% of the hours with real-time interruptions. During 37% of the hours with interruptions, the real-time LMP was less than $70/MWh. The ISO is investigating possible remedies to increase the frequency that the Real-Time Price-Response Program outcomes are consistent with the program’s design objectives.

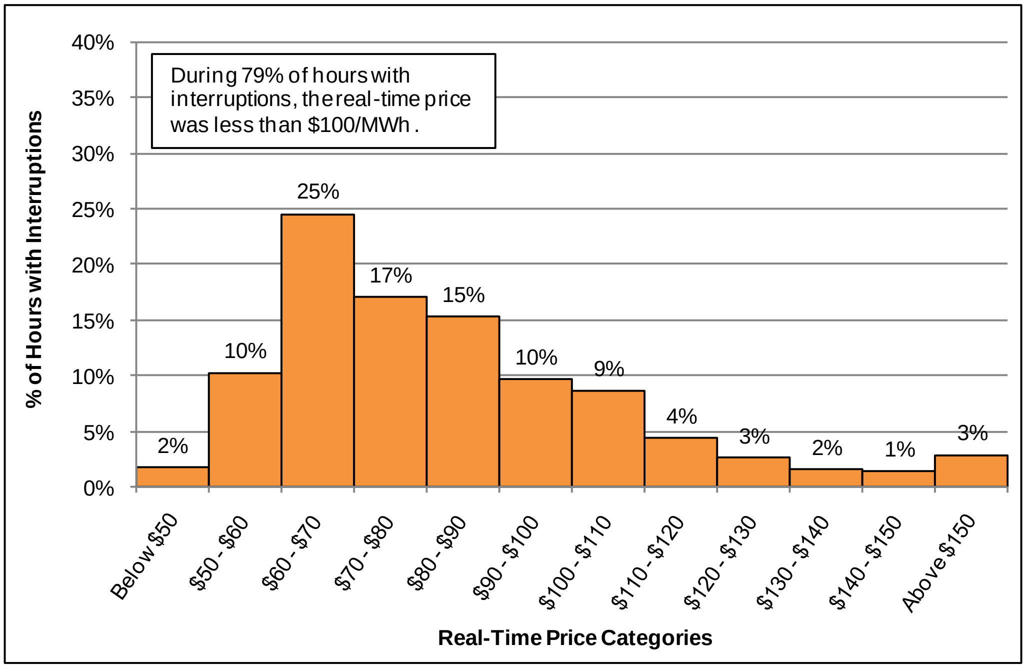

Figure 8-5: Real-time price-response activations with real-time LMPs.

Note: Only hours eligible for the Real-Time Price-Response Program were considered—winter hours: 2:00 p.m. to 6:00 p.m. and summer hours: 12:00 p.m. to 6:00 p.m. Values in the figure sum to more than 21% because of rounding.

8.5 Real-Time Demand-Response and Profiled-Response Program Audit Performance, August 15, 2007

While OP 4 was declared on five days in 2007, these events either occurred outside load-response program hours (i.e., most of the 2007 OP 4 events occurred on weekends) or were not severe enough to require the dispatch of reliability program resources. Because reliability program resources were not called in 2007 during program hours (i.e., nonholiday weekdays between 8:00 a.m. and 6:00 p.m.), the ISO conducted an audit on August 15, 2007, of the resources participating in the Real-Time Demand-Response and Profiled-Response Programs in accordance with the ISO's load-response program rules.[136] On that day, all the real-time reliability program resources were activated 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 from 1:00 p.m. to 5:00 p.m. A limited number of assets with supplemental capacity agreements in Southwest Connecticut also were activated for retest audit purposes in September.

Figure 8-6 illustrates 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.

[136] 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.

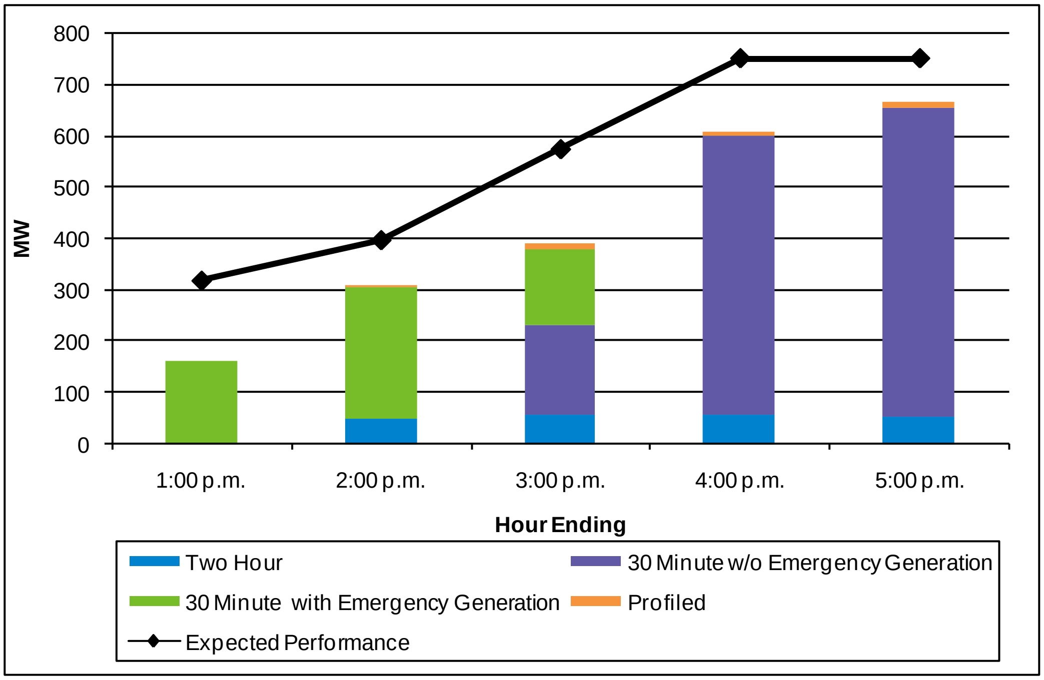

Figure 8-6 Real-time demand-response audit performance, August 15, 2007.

The total energy reduction from these reliability-program resources over the audit period was 2,142.9 MWh, which was 77% of the enrolled amount. The performance of real-time demand-response resources is measured as the ratio of the actual megawatt-hour of load reduced during a load-response or audit event to the expected megawatt-hour of load to be reduced. The expected megawatt-hour 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 77% during the August 15, 2007, audit event is, therefore, equivalent to 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. 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 under-performs during a load-response or audit event, the capacity rating of the asset is reduced going forward.

To encourage more accurate load-curtailment capability estimates, the FCM rules strongly encourage annual preseason audits of demand-response assets to justify capacity payments in months that do not have load-response events. Under the FCM rules, for example, if a demand-response provider did not audit its resources in May, and no load-response events occurred in June, the demand-response provider would receive no capacity payment for June. Such preseason audits should improve the accuracy of load-curtailment capability estimates, which in turn will improve performance factors.

8.6 Demand-Response Reserves Pilot Project

On November 29, 2005, FERC approved ISO tariff revisions to establish the Demand-Response Reserves Pilot Program (DRR Pilot).[137] The DRR Pilot consists of two distinct subprojects with concurrent timelines to meet its objectives and to address two specific goals: (1) determine the ability of demand resources to respond to reserve-activation events compared with off-line and on-line generation resources; and (2) evaluate lower-cost, two-way communication alternatives to the current combination of SCADA (supervisory control and data acquisition) and Electronic Dispatch Remote Intelligent Gateway technology that presently is required to connect dispatchable resources to the ISO. The experience gained in the DRR Pilot will help the ISO achieve the following long-term goals:

- Determine how and when to allow demand-response resources to participate in all wholesale electricity markets (particularly electric energy and reserves) to the greatest extent possible
- Ensure that the energy, capacity, and reserve products that market resources provide (i.e., generation and demand-response assets) are functionally equivalent for meeting the needs of the system operators
- Recognize the behavioral and technological differences between generation and demand-response resources to reduce barriers to entry and to encourage all potential resources to participate in as many markets as practicable

Approximately 23 MW of demand-response resources participated in the DRR Pilot for the winter 2006/2007 season. Activation of the DRR Pilot resources started on October 2, 2006. Ninety-four additional resources were selected to participate in the DRR Pilot for the summer 2007 season, totaling 38 MW of demand response. Resources from among various demand-response resource types participated in the pilot, including weather-sensitive loads, non-weather-sensitive loads, emergency generation, and load-reduction resources. The majority of the megawatts from the summer 2007 season were load-sensitive resources in Connecticut. The results of the DRR Pilot will be used to determine the types of demand-response resources that can provide functionally equivalent, nonsynchronized operating reserves using alternative telemetry.

8.7 Demand Resources Conclusions

In 2007, demand-side participation in wholesale electricity markets grew in both breadth and depth. The new market designs, which recognize different demand-resource categories, have provided breadth, and the new enrollments in each demand-resource category have provided depth. The added variety of programs and total number of program participants are signs that demand-response capabilities are reaching new customers that are taking advantage of the cost reductions offered by demand participation in wholesale markets. Two existing demand-response programs—the ISO's price-response programs—have had performance issues. The DALRP had a design flaw recognized by the ISO. The smaller Real-Time Price-Response Program has not met its design objectives and should be reviewed. These performance issues can be overcome and should be viewed as part of the necessary learning process that comes with the type of growth in demand-response programs New England has achieved during the past year.

[137] *Letter Order Accepting ISO New England, Inc.'s Filing of First Revised Sheet 7014 et al. to FERC Electric Tariff, and Amendments to Appendix E of Market Rule 1 to Establish a Demand-Response Reserve Pilot Program,* FERC Docket No. ER05-1450-000 (November 28, 2005).

In 2007, with the advent of the Forward Capacity Market, the ISO has made strides in its market design for demand resources. As part of the FCM settlement, new categories of demand resources are being qualified to receive capacity credit and capacity transition payments. These new categories are energy efficiency, load management, and distributed generation.

Demand-response programs continued to grow at a quick pace. Maine had the most growth between 2006 and 2007 at 28% of the total growth, despite having an average of only 9% of the New England load. The advent of the Forward Capacity Market with its locational requirements should provide appropriate locational price signals in the future.

Two programs, the DALRP and the Real-Time Price-Response Program, had large numbers of interruptions relative to their originally intended design. In the case of the DALRP, this was caused by flaws already identified by the ISO. Additionally, the Real-Time Price-Response Program is not meeting its goal of interrupting load at or above $100/MWh in the Real-Time Energy Market. During 79% of the time when demand response was activated, real-time prices fell below the target minimum of $100/MWh. Currently, only 98 MW of load is enrolled in the program, and the enrollment has dropped during 2007. The ISO has recognized the issues with the price-response programs and has committed to review them in consultation with NEPOOL stakeholders and state utility regulators.

Section 9
Oversight and Analysis

The market monitoring structure implemented by the ISO relies on two independent market monitoring units: the ISO's Internal Market Monitoring Unit (INTMMU) and the Independent Market Monitoring Unit (IMMU), 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 an additional, 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.

The results of market monitoring for 2007 show that New England's wholesale electricity markets continue to be competitive overall. The competitive benchmark analysis indicates that the observed bidding behavior is consistent with a competitive market. The market share, residual supply index, and HHI analyses indicate that New England's wholesale electricity markets continue to be structurally competitive.

Less competition for the supply of wholesale electricity products takes place in transmission-limited areas. This is particularly a problem when local units are committed frequently for reliability reasons. These units have costs above the clearing prices and are compensated through NCPC. Analysis of NCPC payments in 2007 indicates the need for review of the NCPC mitigation rules.

New England provided an improved environment for new investment by natural-gas-fired resources in 2007. According to the metric developed by FERC for comparison across power pools, a natural gas combined-cycle generator with a 7,000 Btu/kW heat rate could have earned $157,000/MW in 2007. This is a 51% increase from 2006. The predominant factor was the addition of the transition payment, although without this, the increase in earnings still would have been 16%.

This section provides information on the specific role of market monitoring in responding to violations of the market rules. Market monitoring and mitigation activities and resource audits are discussed, and NCPC mitigation thresholds are reviewed. Specific results are presented for a number of analyses of competitive market conditions.

9.1 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[138]
- 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
- 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 tariff, market-behavior rule, or the *Energy Policy Act of 2005* (EPAct)[139]
- Providing support to the ISO in administering FERC-approved tariff provisions related to 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

9.2 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

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

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

systemwide pivotal suppliers. This subsection discusses how the ISO mitigates economic withholding, which is one behavior that interferes with the competitiveness and efficiency of the markets. It also summarizes the results of the market monitoring and mitigation and resource audits that took place in 2007.

9.2.1 Economic Withholding

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

A conduct-impact test for triggering mitigation is used in New England. First, supplier conduct is tested to determine whether the supplier may have attempted withholding. If it fails this conduct test, a test for market impact is applied. If a supplier fails this test by increasing market prices by more than a defined threshold, mitigation is imposed. The mitigation imposed for economic withholding is to replace the supplier's offer with a reference level intended to represent the supplier's full incremental costs.

9.2.2 *Energy Policy Act* and Federal Energy Regulatory Commission Market-Behavior Rules

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 the EPAct. If the Internal Market Monitoring Unit finds a potential violation of EPAct or the market-behavior rules, it is obligated to make a referral to FERC.

On January 17, 2007, FERC approved five settlements of enforcement matters and assessed civil penalties totaling $22.5 million. In the only settlement affecting New England, NRG Energy (NRG) agreed to pay a $500,000 civil penalty to settle violations of FERC market-behavior rules that resulted from the misrepresentation of the status of a generating facility in New England.[140] NRG was found to have intentionally misrepresented that the generating plant was available when it was not. The misrepresentation resulted from the actions of a single employee and did not involve NRG senior management. NRG took immediate corrective action, including reporting the incident to FERC and the ISO. In addition to the civil penalty, NRG agreed to undertake a one-year compliance program

[140] *Order Approving Stipulation and Consent Agreement Re: NRG Energy, Inc.* FERC Docket No. IN07-6-000. 118 FERC ¶ 61,025 (January 17, 2007). Available online at http://elibrary.ferc.gov/idmws/doc_info.asp?document_id=4471974.

that involves submitting semiannual filings containing the results of plant-outage audits for the previous six-month period.

On July 27, 2007, FERC issued show-cause orders that made preliminary findings of market manipulation and proposed civil penalties totaling $458 million in two investigations involving traders' unlawful actions in natural gas markets. Amaranth was given 30 days to show why it should not be assessed civil penalties and disgorge profits totaling $291 million for manipulating the price of FERC-jurisdictional transactions by trading in the NYMEX Natural Gas Futures Contract in February, March, and April 2006.

In the Amaranth case, traders sold large amounts of monthly gas contracts in the last 30 minutes of the trading of NYMEX for the March, April, and May 2006 gas monthly contracts. The effect of these sales was to lower the clearing price for month-long gas contracts. The manipulation affected indices used for month-long physical gas contracts. A variety of monthly gas contracts in the over-the-counter markets, such as the Inter-Continental Exchange (ICE), are priced as NYMEX plus a locational adjustment (basis differential).

Given that generators should not include monthly contract costs in their offers, the Amaranth market manipulation did not affect the ISO's daily electricity prices. Because the ISO's INTMMU uses daily, not monthly, gas prices in constructing marginal cost estimates, market monitoring and mitigation were unaffected by Amaranth's manipulation of the gas market.

9.2.3 Market Monitoring and Mitigation Results

Mitigation was triggered 16 times during 2007. Thirteen mitigation events were for economic withholding in the Real-Time Energy Market, and the remaining three mitigation events were for economic withholding for NCPC. In addition to taking these specific actions, the INTMMU had nearly daily discussions with individual participants concerning specific market behavior. The systemwide thresholds did not trigger mitigation of electric energy suppliers that were pivotal in 2007.

9.2.4 Resource Audits

Market Rule 1, Appendix A, Section 4.2.2, authorizes the ISO to verify forced outages and thus monitor the physical withholding of resources.[141] The INTMMU uses all available data to determine whether a plant inspection is warranted. If an inspection is appropriate, the ISO contacts both the plant management and the lead participant to coordinate access to the plant and a visual inspection of the reported cause of the forced outage. If the results of a plant inspection suggest that the resource owner has physically withheld the resource, the ISO obtains appropriate additional information. If the completed review shows that physical withholding has taken place, the ISO may impose sanctions, as outlined in Appendix B of Market Rule 1.[142]

During 2007, the INTMMU requested detailed plant information and operator logs for a number of cases. In each case, the INTMMU monitored for potential physical withholding of a resource and determined that a plant inspection was not warranted. However, as part of its routine information-gathering process, the INTMMU visited one generating station during the year.

[141] This section of Market Rule 1, Appendix A, can be accessed online at http://www.iso-ne.com/regulatory/tariff/sect_3/.

[142] Market Rule 1, Appendix B, can be accessed online at http://www.iso-ne.com/regulatory/tariff/sect_3/.

9.3 Review of NCPC Mitigation

Market Rule 1 includes provisions that mitigate (or limit) the total NCPC payments made to a generating resource if it violated prespecified offer conduct and market impact thresholds.[143] The current thresholds for mitigating NCPC were designed at the time of the original SMD market filing in 2002. At that time, New England did not have a locational capacity market or capacity market transition payments, and the systemwide capacity market produced limited revenue (see Section 3 for more information about the FCM and capacity transition payments). In addition, the mitigation rules in 2002 were instituted against a background of a lack of investment in congested areas.[144]

To compensate for the limited revenues from the systemwide capacity market and encourage investment in congested areas, the ISO proposed, as part of the July 2002 SMD filing, NCPC and energy market mitigation thresholds that allowed generators to recover a portion of their fixed cost. The energy thresholds were tied to the estimated cost of a proxy combustion turbine, including its average fixed cost. In May 2003, in an order on reliability-must-run (RMR) and capacity market issues, FERC ordered the establishment of Peaking-Unit Safe-Harbor thresholds for incremental energy offers, thus providing additional fixed-cost recovery where appropriate.[145]

9.3.1 NCPC and the Forward Capacity Market

FERC has found that the FCM and the transition payments provide just and reasonable compensation for the fixed costs of capacity. In addition, the locational Forward Reserve Market and real-time reserve payments provide a forward price signal for investment in congested areas and real-time shortage pricing. As a result of these market design improvements, the PUSH thresholds have been eliminated. In contrast, the NCPC mitigation thresholds have not been adjusted. In the current market design, NCPC mitigation thresholds cannot be justified on the basis of inadequate fixed-cost recovery. A review of NCPC mitigation thresholds is appropriate at this time.

In addition to the fixed-cost recovery and capacity transition payments provided by the FCM, it also changes the incentives for participants offering resources to the energy markets. Under the FCM, generators will have their peak energy rent (PER) reduced when real-time prices exceed a threshold value, but the calculation does not affect NCPC payments.[146] Participants could react by shifting their net-revenue recovery out of the energy market and into NCPC revenues, for example, by making their resource less flexible so that it runs through shoulder and off-peak hours.

9.3.2 Transmission Improvements

Transmission improvements can reduce or eliminate NCPC in a constrained area. NCPC amounts reported in this 2007 report may not be representative of future conditions with improved transmission. It is less well recognized that the often lengthy construction period for new transmission can create the need for committing units for reliability. As transmission is taken out of service for

[143] Net Commitment-Period Compensation (also known as daily reliability payments) is covered in detail in Section 6.1.

[144] Filing letter, FERC Docket ER02-2330-000 (July 13, 2002), p. 32.

[145] Filing letter, FERC Docket ER03-563-000 (May 30, 2003).

[146] *Peak energy rent* refers to energy profits above thresholds specified by the FCM Settlement Agreement. Capacity payments are made net of these profits. The PER deduction is determined by calculating the difference between the real-time energy price and a strike price derived from the incremental hypothetical cost of a proxy unit. (FCM Settlement Agreement Section V.B).

construction, resources may be called on in out-of-merit order for local reliability. These resources become new sources of NCPC.

This is more likely to happen in the next few years because of the large increase in new transmission projects scheduled. Few new transmission projects were undertaken during 2002 through 2005. The cumulative new construction costs during these four years totaled $344 million. By comparison, the planned transmission construction costs are $770 million for 2008 and $1.962 billion for 2009.

9.3.3 Analysis of Recent NCPC

The ISO conducted an analysis of NCPC that focused on the structural ability of resources to earn NCPC, the incentive and net revenues to be earned, and the adverse effects. The analysis is designed to understand the root cause of NCPC incentives and to draw lessons for future improvements.

9.3.3.1 NCPC Concentration

Over the past three years, NCPC has consistently been highly concentrated among a small number of units. These units are committed most frequently and provide large amounts of out-of-merit electric energy. The specific generators may shift from year to year with changes in the network and Reliability Agreements.

The data in Table 9-1 demonstrate that a small set of generators receives the bulk of NCPC payments. In 2007, over 50% of NCPC payments were made to just two resources.

Table 9-1
Concentration of NCPC among Resources

Year	Number of Resources that Combined Receive Greater than 50% of NCPC	Number of Resources that Combined Receive Greater than 90% of NCPC
2005	3 generators	14 generators
2006	4 generators	17 generators
2007	2 generators	15 generators

The generators receiving the most NCPC also are committed the most frequently. This provides them with an ability to predict that they will be committed for reliability needs. The ability to predict their out-of-market commitment allows the generators to offer their units' energy and start-up profiles strategically to maximize the benefit of generous mitigation thresholds. For example, a resource may exaggerate its minimum run time and assume that the ISO still will commit it for reliability because of its strategic position.

Figure 9-1 illustrates this concentration for the entire set of resources in New England for 2007. The pattern is similar for 2005 and 2006. The graph is cumulative (e.g., it shows that the first 20 units received 92.2% of the systemwide NCPC). The majority of resources receive little or no NCPC; they would be unaffected by any changes to NCPC mitigation rules.

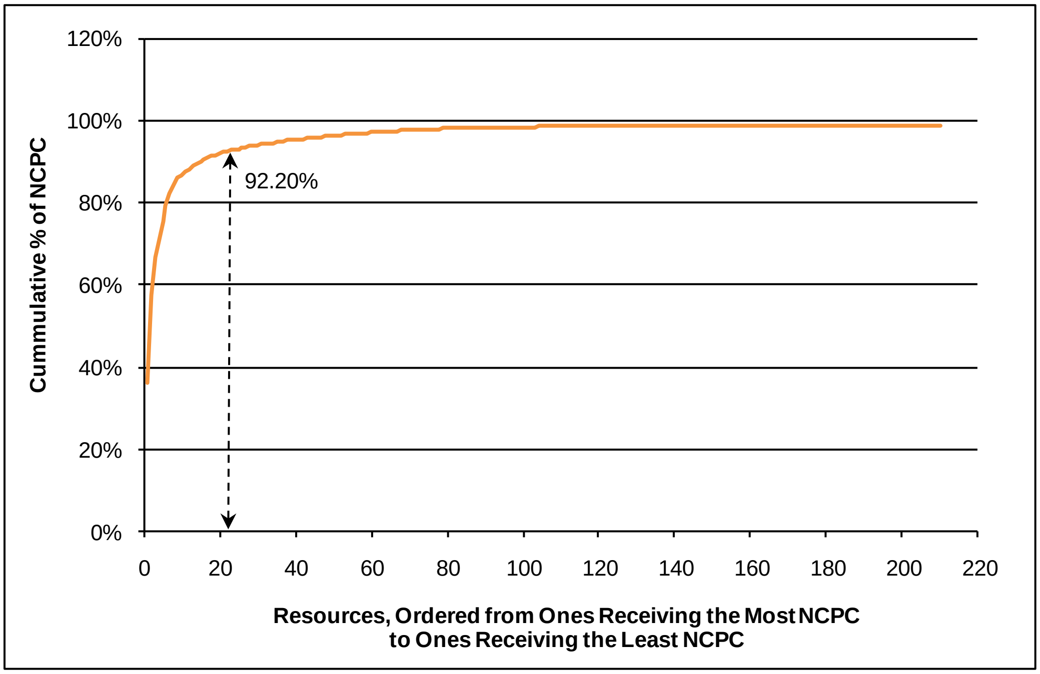

Figure 9-1: NCPC payment concentration, 2007.

The concentration of NCPC payments among resources suggests that the resources face little competition in filling their strategic reliability roles.

9.3.3.2 Net Revenue Earned through NCPC

To confirm that participants have a financial incentive to earn net revenue from NCPC under the current rules, the ISO estimated the net revenue for two units that received the majority of the revenues during 2007. The net revenues from NCPC payments for the two units committed most frequently for transmission support ranged from \$2.3/kW-month to \$3.3/kW-month.

9.3.3.3 Adverse Effects of Current Rules and Behavior

Increased NCPC payments alone are not necessarily objectionable, but they are associated with two problems. First, large amounts of NCPC undermine the benefits of the existing energy market clearing-price auction. Second, the pursuit of NCPC revenues creates inefficiencies and harms other generators.

NCPC undermines the benefits of the existing energy market clearing-price auction because NCPC is not a cost that load-serving entities can hedge. It is a unit-specific cost that is difficult for LSEs to predict and for which no forward contracting exists due to the lack of transparency. In contrast, the clearing-price mechanism of the energy market allows transparency and forward contracting.

NCPC also undermines the energy market clearing-price auction because it reduces the incentive to offer at marginal cost and in the most flexible configuration. In effect, NCPC creates pay-as-bid incentives that interfere with the clearing-price market without the benefits of market competition.

The pursuit of NCPC revenues also creates inefficiencies and harms other generators. Net revenues from NCPC provide incentives for suppliers to invest less in flexibility or to make operational choices that reduce physical flexibility. For example, by increasing the time-based parameters (e.g., minimum run time), an NCPC resource can increase its payments. By choosing a particular facility configuration to increase its minimum operating level, an NCPC resource can increase its payments to cover more megawatts. The NCPC revenues for the two largest NCPC recipients support the hypothesis that resource bidders have an incentive to alter their offers to maximize NCPC revenue.

The first result of less flexible resources is an inefficient dispatch and an efficiency loss. The second result is that out-of-merit energy is forced onto the system as "must-take." In effect, the energy is priced at zero in the competitive clearing-price market. This translates into an artificially lower supply curve.

9.3.4 NCPC Mitigation Conclusions

An analysis of the recent NCPC experience has yielded several observations:

- The majority of NCPC payments is made to a few generators. As shown in Table 9-1, two units received more than 50% of the NCPC payments in 2007. This is consistent with their unique transmission status and lack of competition for transmission services.
- An in-depth review of the revenue of the two units confirmed that they have received significant revenue above their variable cost. This revenue provides an incentive to offer resources with less flexible operating parameters, which reduces efficiency.
- The commitment of these and other units at their operating minimum has adverse effects. It distorts the supply curves in their constrained areas, lowering the price for other generators and reducing the efficiency of the dispatch
- NCPC is not part of the clearing-price market. This undermines the benefits of a clearing-price market, such as the ability of consumers to hedge their costs and the incentive for competitors to offer at marginal cost.

The NCPC compensation mechanism was intended to prevent losses. Yet the structure of NCPC provides the opportunity for a few resource owners to receive significant net revenues from NCPC, the incentive to offer resources with less flexible operating parameters, and, as a result, the possibly to distort the market. FERC's acceptance of the FCM as a just and reasonable payment for capacity suggests that generous NCPC mitigation thresholds are not defensible as payment for fixed costs.

To address the identified problems, the ISO is considering NCPC mitigation rule changes with more restrictive thresholds.

9.4 Analysis of Competitive Market Conditions

This section presents analyses of competitive market conditions during 2007. It includes analyses of market share, pricing efficiency, and market entry.

9.4.1 Herfindahl-Hirschman Index for the System and Specific Areas

Market concentration is a function of the number of firms in a market and their respective market shares. One measure of market concentration is the *Herfindahl-Hirschman Index* (HHI). The HHI is calculated by summing the squares of the individual market shares of all market participants. The HHI reflects the distribution of the market shares, giving proportionately greater weight to the market shares of the larger firms, in accordance with their relative importance in competitive interactions. For electricity markets, shares are measured by megawatts of generating capacity.

The HHI is not a sufficient indicator of market concentration in wholesale electricity markets. The metric does not account for contractual entitlements to generator output that reduce the level of market power associated with any given supply-ownership concentration, as measured by the HHI. In addition, the HHI ignores the effect that transmission constraints can have on the market. Load pockets that result from these constraints may be less competitive than the systemwide HHI would suggest. Finally, the HHI does not recognize the effect of an extremely inelastic demand curve and the associated inability to store electricity. The inability of consumers to reduce demand in response to higher prices permits prices to rise in the short term.

These limitations notwithstanding, HHI still is a useful indicator to monitor. Market concentration measured by the HHI is conventionally divided into three regions, broadly characterized as follows, which provide a framework for market-concentration analysis:

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

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

Figure 9-2 shows the HHI for New England internal resources based on summer capabilities and the responsibilities of the lead participant to offer the generating unit to the market. The values shown were developed from participant information collected by the INTMMU. The marketwide HHI displays the following:

- A steady decline from the opening of wholesale electricity markets in New England
- A slight increase in winter 2002/2003 when a participant was assigned certain generators with previously unclassified generator ownership
- A slight upward movement during the third quarter of 2003 due to the beginning of the commercial operation of a large generating facility owned by an existing participant
- Little variation during 2004
- A decrease in January 2005 following the divestiture of USGen's approximately 4,000 MW New England asset portfolio due to USGen's bankruptcy. (Dominion Energy Marketing acquired about 2,700 MW of thermal units from USGen, while TransCanada Power Marketing and Brascan Energy Marketing purchased hydro units.)
- An increase in June 2005 due to the transfer of assets between companies. Because the participant company that received the assets already owned significant generation, the transfer resulted in its having the largest portfolio in New England.
- Little variation during 2006
- A slight decline in 2007

Throughout the period of markets in New England, the HHI market concentration metric has been below the U.S. Department of Justice benchmark for an unconcentrated market. The average HHI for

2007 is about 670, well below the DOJ benchmark for an unconcentrated market, and represents a slight drop from the 2006 average HHI of about 700.

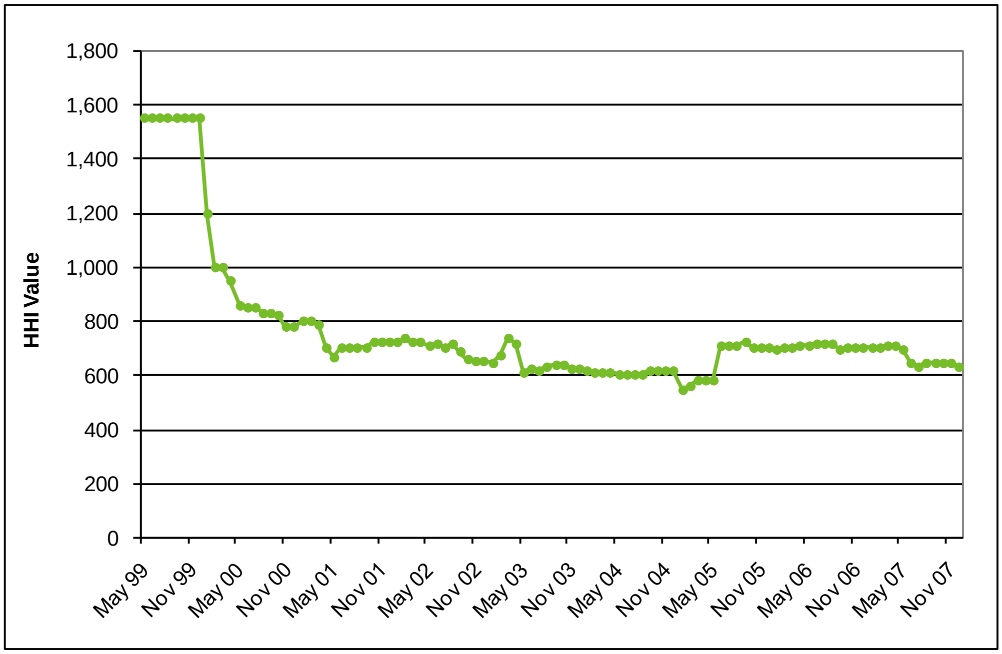

Figure 9-2: Herfindahl-Hirschman indices for New England, May 1999 to December 2007.

As part of its market assessment function, the ISO also develops an HHI for each load zone, as shown in Figure 9-3. At the zonal level, indices are all highly or moderately concentrated. The Vermont and NEMA load zones have the highest HHIs, indicating the highest potential for market-power concerns. The Vermont calculation should be viewed with caution because this state has a relatively small capacity to generate electricity, significant import capability, and vertically integrated utilities. The NEMA load zone, which frequently needs out-of-merit operation for transmission support, has an HHI in the highly concentrated range; however, the HHI for this load zone declined significantly in 2005.

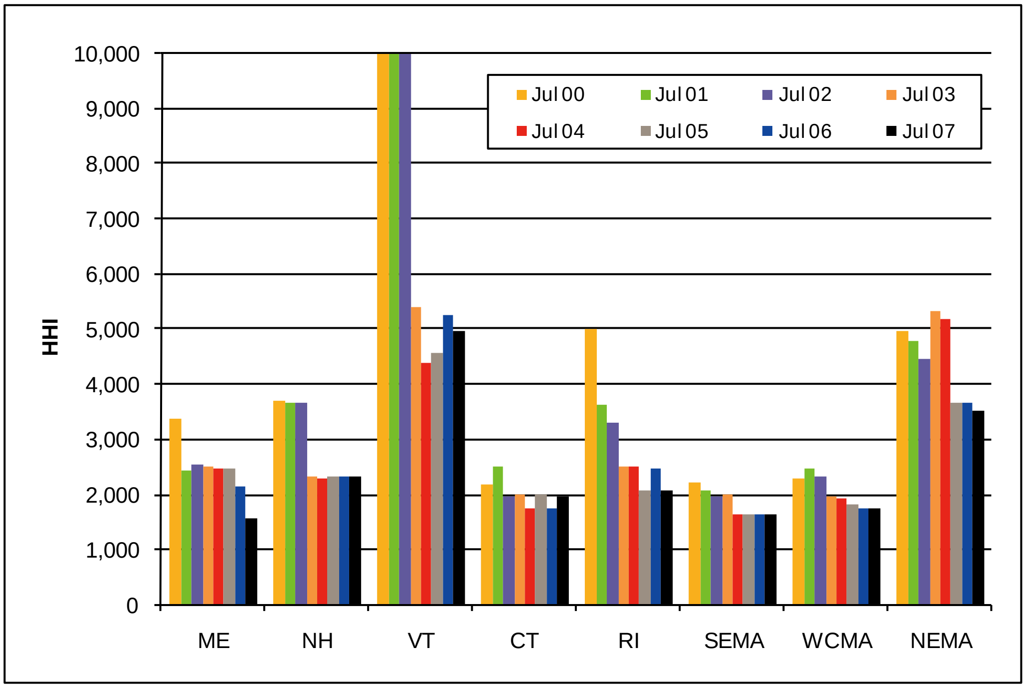

Figure 9-3: Herfindahl-Hirschman indices by load zone.

9.4.2 Forward Contracting

Estimates of the level of forward contracting and self-supply generation in New England are important in evaluating how well New England's markets are working. Forward contracting insulates load from short-term price volatility and serves as an incentive for generators to offer generation at marginal cost.[147]

Calculations for January through December 2007 show that, on average, at least 38% of total real-time load obligation was either forward contracted or covered by a physical hedge through the ISO's settlement system. For each month of 2007, as shown in Figure 9-4, the degree of forward contracting was at least 38% of real-time load obligation. In 2006, the average was 52%. These calculations tend to understate the degree of forward contracting that actually takes place to the extent that bilateral contracts exist but are not settled through the ISO's centralized settlement system. Conversations between the INTMMU and market participants suggest that the drop in hedging through the settlements system during 2007 reflects an increased use of bilateral contracts settled independently of the ISO. Hence, while these numbers are useful, they are only indicative of the forward positions held by participants.

[147] David Newbery, "Power Markets and Market Power," *The Energy Journal* 16:3 (1995).

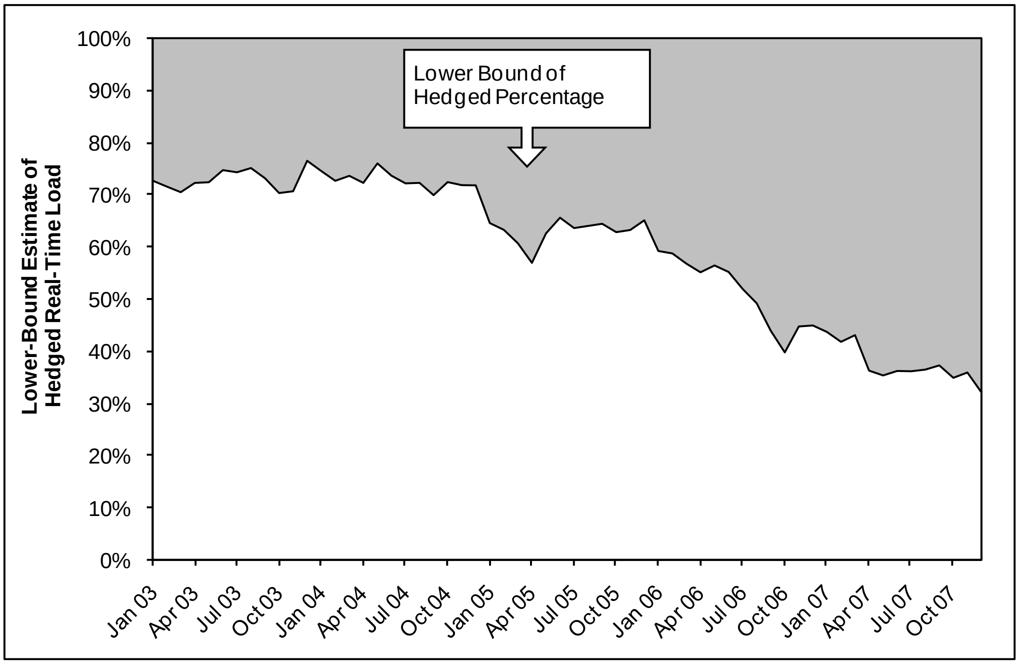

Figure 9-4: Lower bound of real-time load as hedged through the ISO settlement system.

9.4.3 Residual Supply Index

The *Residual Supply Index* (RSI) measures the hourly percentage of load (MWh) that can be met without the largest supplier. It indicates the potential of individual bidders to influence the market-clearing price. The index is computed as follows:[148]

(Eq. 1)

$$\text{RSI} = \frac{(\text{Total supply} - \text{largest seller's supply})}{(\text{Total demand})}$$

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. If the RSI exceeds 100%, alternative suppliers have sufficient capacity to meet demand. A pivotal supplier can in theory unilaterally drive prices above the competitive level, subject to prevailing offer caps. The profit-maximizing offer of the pivotal supplier may be below the offer cap if the demand not met by other, nonpivotal suppliers is price sensitive.

The RSI is 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 the market metric developed in the competitive benchmark analysis (described in Section 9.4.4).[149] That is, as RSIs fall, markups tend to rise.

[148] *Total supply* is defined as the total of generators' economic maximums. *Demand* is defined as actual load.

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

On July 9, 2003, FERC accepted the ISO's request to implement a pivotal-supplier trigger for evaluating a pivotal supplier's energy-supply offers for possible mitigation.[150] In this proposal, a pivotal supplier is defined as a market participant whose aggregate energy-supply offers for a particular hour are greater than the New England supply margin.[151] The calculation of the RSI, described previously, is consistent with the requirements outlined in the FERC docket.

Table 9-2 shows the number of hours in each month of 2007 that the RSI was below 100% and below 110%. RSIs generally are lowest during periods of high demand. This analysis shows that pivotal suppliers existed during 115 hours in 2007 when the RSI was below 100%. The majority of the hours with pivotal suppliers occurred during high-demand summer days.

Table 9-2
Residual Supply Index, 2007

Month	Number of Hours RSI <100%	Number of Hours RSI <110%	Average Monthly RSI	Maximum RSI	Minimum RSI
Jan	0	10	147	201	103
Feb	0	1	142	183	109
Mar	0	4	138	183	105
Apr	0	48	129	169	104
May	0	29	134	180	102
Jun	26	50	149	211	89
Jul	12	83	140	206	97
Aug	49	136	135	200	89
Sep	21	49	140	193	95
Oct	0	31	139	187	102
Nov	0	3	143	343	108
Dec	7	64	135	186	97
Total	**115**	**508**	**139**	**343**	**89**

As Table 9-3 shows, 2007 had fewer hours than 2006 during which there were pivotal suppliers due to the lower peak demand during 2007. The increase in hours with an RSI less than 110% is expected because of the higher average load levels in 2007 compared with 2006.

[150] *Order on Proposed Tariff Revisions.* FERC Docket No. ER03-849-000. 104 FERC ¶ 61,039 (July 9, 2003). In this docket, FERC noted that a structural problem exists when suppliers become pivotal; they have market power because at least a portion of their offers must be accepted to maintain reliability, no matter how high the offer price. FERC found it reasonable to evaluate the supply offers of pivotal suppliers to determine whether the suppliers are attempting to exercise market power in the unconstrained pool and, thus, whether their offers should be mitigated. See http://www.iso-ne.com/regulatory/ferc/orders/2003/jul/General_Mitigation_Order_070903.pdf.

[151] The *supply margin* for an hour (i.e., the available generation beyond the amount needed to meet demand for that hour) is equal to the total of energy supply offers for that hour, up to and including the economic maximum, minus the total system load (as adjusted for net interchange with other control areas and including operating reserve).

Table 9-3
Residual Supply Index, 2004, 2005, 2006, and 2007

Year	Number of Hours RSI <100%	Number of Hours RSI <110%	Average Monthly RSI
2004	43	247	141
2005	311	865	138
2006	154	448	141
2007	115	508	139

The results for the RSI analysis are consistent with other analyses that show relatively good market performance in New England. There was a pivotal supplier during only 1.3% of total hours in 2007, a 27% decrease from the 1.8% of hours in 2006 during which there was a pivotal supplier. This RSI analysis is somewhat conservative and may overstate the number of hours in each month that one or more suppliers were pivotal. It does not account for hours when a participant is pivotal for reserve. It also does not take into account contractual relationships that affect the amount of load obligation a supplier may have in any hour and that obligation's influence on market behavior.[152] The ISO will continue to monitor the existence of pivotal suppliers and assess their influence on the market.

9.4.4 Competitive Benchmark Analysis

In 2002, the INTMMU developed a tool (the ISO model) for conducting competitive benchmark analyses. The ISO model 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.[153] The ISO uses this tool to identify trends in the competitiveness of New England's wholesale electricity market.

The *competitive benchmark* (benchmark price) is an estimate of the market-clearing price that would result if all market participants acted as price-takers, offering their electric energy at incremental marginal cost, and if the market operated with perfect efficiency in an unconstrained system. The benchmark price can be compared with either actual market prices or other market measures. The benchmark price accounts for production costs, including environmental and variable operations and maintenance (O&M) costs, unit availability, and net imports. It thus represents the estimated incremental costs associated with the least expensive generating unit not needed to serve demand in a given hour.

Table 9-4 compares the annual average benchmark price with a second modeled price (bid-intercept price) and actual real-time LMP at the Hub. The bid-intercept is the price at which market demand intersects the aggregate supply curve, derived from the supply offers from all generating units but ignoring unit-operating constraints. This is the same methodology used for calculating the competitive benchmark price. Comparing the bid-intercept price with the benchmark price over time can help assess the competitiveness of the market. Comparing the aggregate bid-intercept price with

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[152] Richard Green, "The Electricity Contract Market in England and Wales." *Journal of Industrial Economics* XLVII:1(1999):107–124.

[153] James Bushnell and Celeste Saravia, *An Empirical Analysis of the Competitiveness of the New England Electricity Market.* (Berkeley: University of California Energy Institute, January 2002). The study report is available online at http://www.iso-ne.com/pubs/spcl_rpts/2002/empir_assess_competitiveness_bushnell.pdf.

the real-time Hub price provides a measure of the error in the modeling method used to calculate the competitive benchmark and bid-intercept prices.

Table 9-4
ISO Model Market Price Measures

Price Measure	2007 Price ($/MWh)	Quantity-Weighted Lerner Index (%)				
		2003	2004	2005	2006	2007
Competitive benchmark price	$63.47					
Aggregate bid-intercept price	$64.90	−4	−6	1	1	2
Real-time Hub price	$69.57	9	3	6	6	9

The metric used to compare the total costs derived from the different price estimates is the *Quantity-Weighted Lerner Index* (QWLI), which is a function of the conventional *Lerner Index*. The conventional Lerner Index is widely used to assess the competitiveness of market outcomes and is defined as price minus marginal cost divided by price. The QWLI is defined as the annual market cost based on market prices minus the annual market cost based on marginal cost estimates divided by the annual market cost based on market prices. The ISO analysis calculates two QWLI measures, both using the benchmark price as the measure of marginal cost. The aggregate bid-intercept QWLI treats the model-based aggregate bid-intercept price as the market price in the Lerner index, while the QWLI for the real-time Hub LMP uses the real-time Hub price as the market price. The specific formulas used in the QWLI calculations are shown in equation 2 and equation 3.

$$\text{(Eq. 2)}\quad \text{Bid-Intercept QWLI} = \frac{\sum(\text{bid intercept price} \times \text{load}) - \sum(\text{benchmark price} \times \text{load})}{\sum(\text{bid intercept price} \times \text{load})}$$

$$\text{(Eq. 3)}\quad \text{Real-Time Hub LMP QWLI} = \frac{\sum(\text{Hub LMP} \times \text{load}) - \sum(\text{benchmark price} \times \text{load})}{\sum(\text{Hub LMP} \times \text{load})}$$

Comparing the estimated average aggregate bid-intercept price to the actual average real-time Hub price provides a measure of the error inherent in the methodology used to calculate both the competitive benchmark prices and the aggregate bid-intercept prices. Table 9-4 shows that the bid-intercept QWLI increased from 1% in 2006 to 2% in 2007. This year-to-year change is small. The 2% result for 2007 is consistent with competitive market outcomes. While the QWLI is a useful and intuitive measure of market competitiveness, it is subject to an uncertain amount of 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). Thus, it is more appropriate to examine trends and large movements in the aggregate bid-intercept QWLI than to place emphasis on modest year-to-year changes. The results of the model suggest that the market continued to behave competitively through 2007.

9.4.5 Implied Heat Rates

The market prices for electricity and fuel can be used to derive the heat rate that would allow a generator to break even if it were producing electricity. This *implied heat rate* is useful because it shows a generator's required efficiency level for recovering fuel costs at prevailing market prices of electric energy and its particular fuel. Comparing a generator's heat rate with the heat rates of existing resources can indicate the likelihood of the generator's dispatch and the relative economics of various fuels and generation technologies. For example, if the price of a fuel rises at a rate greater than the price of electricity does, even thermally efficient generators may not be able to recover fuel costs or to earn additional revenues while producing electricity. The situation where efficient generators are unable to recover fuel costs is reflected by implied heat rates that drop below those generators' operational heat rates.

Table 9-5 shows volume-weighted average heat rates at full load for New England generators burning various types of fuel. The table shows the average heat rate for all generators in each fuel category and the estimated heat rates for the most efficient generator. Dual-fueled generators are included in the category of the fuel they burn most frequently.

Table 9-5
Average Heat Rate by Generator Fuel Type, Btu/kWh

Generator Fuel Type	Estimated Average Heat Rate	Estimated Most Efficient Heat Rate
Coal	9,700	8,700
Jet fuel	13,400	12,600
Kerosene	12,100	10,500
Natural gas	8,200	6,900
No. 2 fuel oil	13,900	10,500
Diesel	12,100	11,000
No. 6 fuel oil	10,500	9,200

The implied heat rate is the ratio of the day-ahead Hub LMP in each hour and the next-day price for the applicable fuel. This rate approximates the thermal efficiency that would be required to recover fuel costs and earn additional revenues on the conversion of that fuel to electricity. For example, if the day-ahead LMP were $60/MWh and the day-ahead fuel price were $6/MMBtu, the implied heat rate would be 10 MMBtu/MWh, or 10,000 Btu/kWh. Generators with actual heat rates lower than the implied heat rate recover fuel costs and earn additional revenues on their conversion of fuel to electricity.

Figure 9-5 reports the monthly average implied heat rates for price points on two major interstate natural gas pipelines in New England. The data suggest that gas-fired generators with a thermal heat rate less than 8.2 MMBtu/MWh, the average in New England, typically were recovering fuel costs. The monthly averages obscure the daily fluctuations in implied heat rates that would place specific units in or out of economic-merit order on a given day. The divergence between Algonquin and Tennessee Zone 6 in December is due to gas supply issues as a result of the Sable Island contingency event.

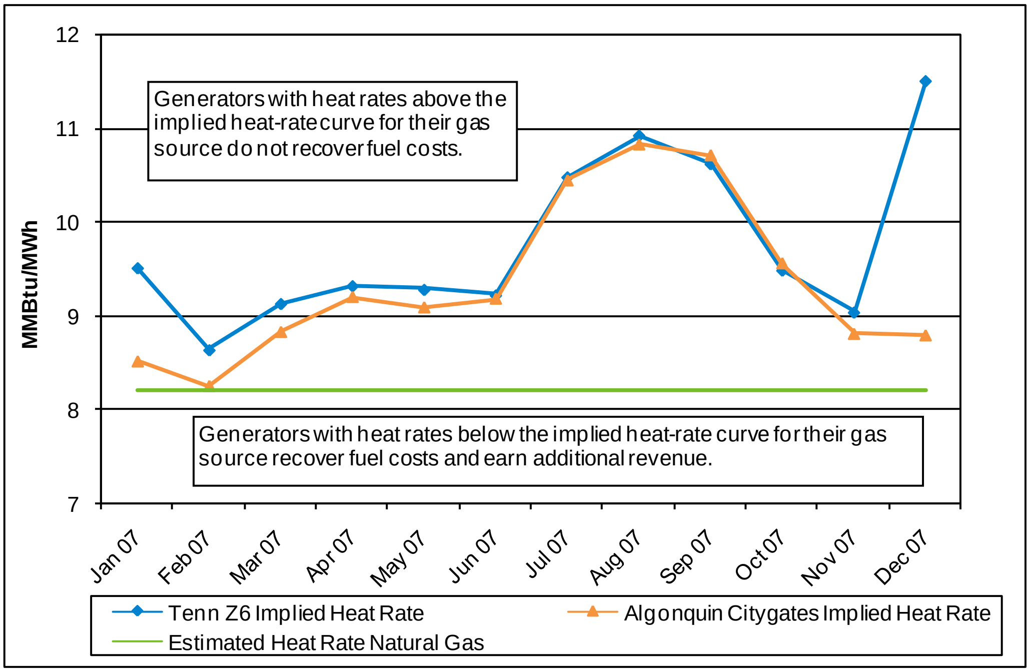

Figure 9-5: Monthly average implied heat rates in New England, natural gas and electricity.

Note: Daily implied heat rates were calculated as the ratio of the average day-ahead on-peak LMP for all nodes with generators of each fuel type to the fuel price. For each month, an average of all days in the month was calculated.

Figure 9-6 reports the implied heat rates for selected petroleum-based fuels. On the basis of average monthly prices, the results show that the average No. 2 fuel oil, jet fuel, and diesel-fueled generators did not recover fuel costs. This is in accordance with ISO observations of oil-fired unit operations; most run only when electricity prices are relatively high. Figure 9-7 shows that the average coal-fired generator typically recovered fuel costs.

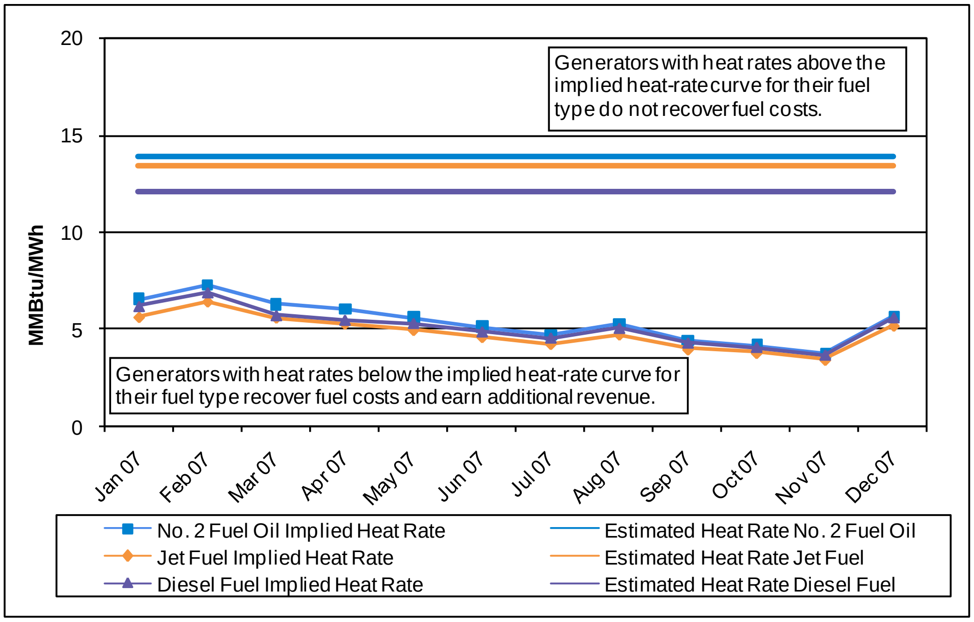

Figure 9-6: Monthly average implied heat rates in New England, petroleum-based fuels and electricity.

Note: Daily implied heat rates were calculated as the ratio of the average day-ahead on-peak LMP for all nodes with generators of each fuel type to the fuel price. For each month, an average of all days in the month was calculated.

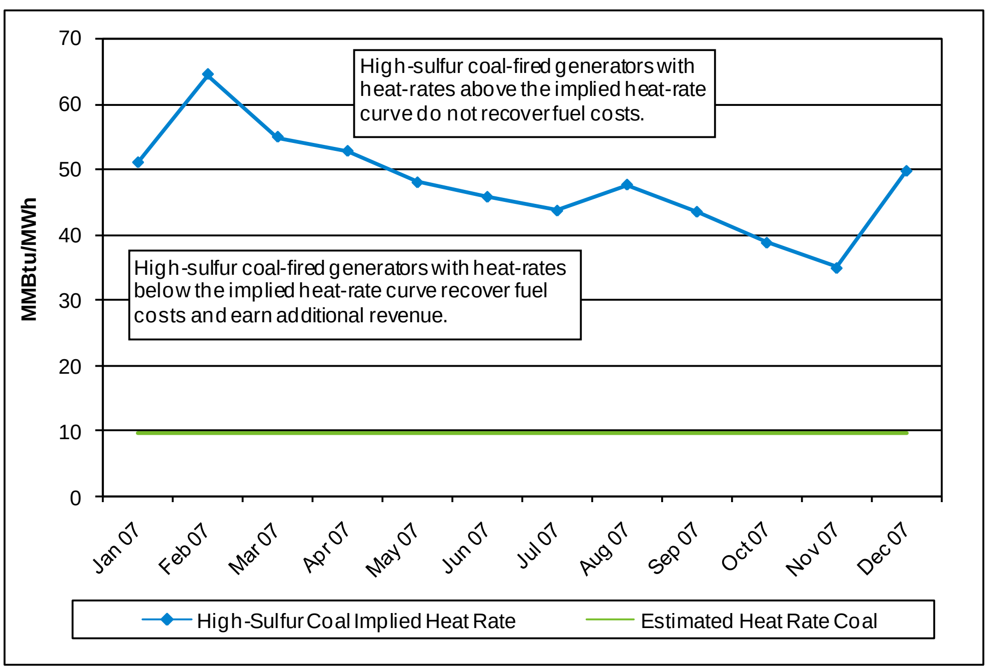

Figure 9-7: Monthly average implied heat rates in New England, coal and electricity.

Note: Daily implied heat rates were calculated as the ratio of the average day-ahead on-peak LMP for all nodes with generators of each fuel type to the fuel price. For each month, an average of all days in the month was calculated.

Figure 9-8 provides a breakdown of the status of the marginal unit (i.e., unconstrained or constrained up or down due to transmission constraints) for each fuel type that was marginal during 2007 (see Section 2.4.2.1). In Figure 9-8, unit types are sorted in decreasing order of the frequency with which they are marginal because they are constrained up for transmission. The figure shows that oil and jet fuel units, which are among the most expensive units in New England, are marginal most often because of transmission constraints, as opposed to setting the unconstrained price for the system. Coal, coal/oil, and hydro units are marginal because of transmission constraints less than 20% of the time. Coal and coal/oil units are almost never marginal and constrained up for transmission. These units generally run in merit and have positive spark spreads relative to the LMPs.[154]

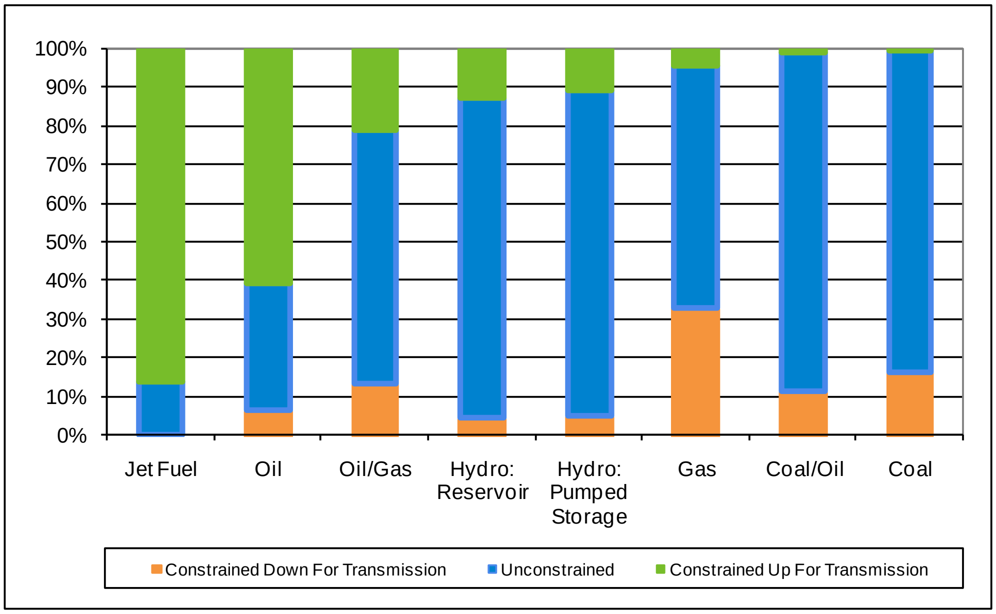

Figure 9-8: Constrained status of marginal resources by fuel type.

9.4.6 Net Revenues and Market Entry

Another market barometer compares market revenues with the revenue requirements for a new generating unit seeking to enter the market. In the long run, the revenues from the energy, capacity, regulation, and reserve markets must be expected to cover the costs of 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 should lead to new entrants and exert downward pressure on prices. The margin between a plant's market revenues and its variable costs (primarily fuel for fossil units) contributes to the recovery of its fixed costs, including nonvariable operating and maintenance 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.

Table 9-6 presents an estimate of the theoretical maximum net revenues for two hypothetical gas-fired generators in New England during 2007. It represents an upper bound of revenue and is not informative about actual financial conditions for many generators in New England. Gas-fired

[154] S*park spread* is a measure of the profits from converting natural gas to electricity based on the wholesale price of electricity and the cost of producing electricity with natural gas. Positive spark spreads indicate that converting natural gas to electric energy is profitable at a given heat rate (i.e., the fuel price times the heat rate is less than the LMP).

generators were modeled because they represent the typical new unit that has been brought on line in New England. Daily marginal costs were calculated for each hour using spot-fuel prices, the assumed heat rates, and other production costs for both an efficient combined-cycle natural-gas-fired plant with a heat rate of 7,000 Btu/kWh and a typical gas-fired combustion-turbine unit with a heat rate of 10,500 Btu/kWh. FERC developed this metric and the specific parameters used for comparison across power pools. It was assumed that the generator ran each hour the price was above its marginal cost, ignoring commitment costs, ramping constraints, and start-up and minimum run times. However, by ignoring start-up costs and generator inflexibility, particularly for combined-cycle units, the calculations overstate actual net revenues.

Table 9-6
Yearly Theoretical Maximum Revenue for Hypothetical Generators
Net of Variable Costs per MW, 2007

Generator	Marginal Cost Formula	Heat Rate (Btu/kWh)	($/MW-Year)			
			2007 Net Energy Revenue	Approximate Capacity Revenue[(a)]	Approximate Ancillary Services Revenue[(b)]	Approximate Theoretical Max. Revenue
Representative combined cycle/ gas fired	(Daily fuel cost x heat rate) + (VOM[(c)] of $1/MWh)	7,000	$119,087	$36,600	$1,437	$157,124
Representative combustion turbine/ gas fired	(Daily fuel cost x heat rate) + (VOM[(c)] of $3/MWh)	10,500	$25,532	$36,600	$31,032	$93,164

(a) The revenue from capacity is the capacity transition payment of $3,050/MW-month multiplied by 12.

(b) The revenue from ancillary services is based on the Regulation Market for combined-cycle units and the Forward Reserve Market for combustion-turbine units. Forward-reserve revenues equal Rest-of-System auction revenues minus performance penalties.

(c) Variable operations and maintenance costs.

Under these assumptions, the combined-cycle plant would have earned a theoretical maximum of about $157,000/MW in the electric energy, capacity, regulation, and reserve markets during 2007, net of variable costs. The combustion-turbine plant would have earned a theoretical maximum of approximately $93,000/MW. For this analysis, unit outages were represented by reducing energy revenues by 5%.

The net revenue of the representative combined-cycle generator in 2007 increased 51% from the 2006 estimate. For the representative combustion turbine, the estimated net revenue increased 96% between 2006 and 2007. If transition payments were excluded from both years, the net revenues still would have increased by 16% and 20%, respectively, for combined-cycle and combustion turbine generators. Some increase in estimated net revenues is to be expected even in the absence of capacity payments. Because of the divergence in relative fuel prices, during periods when oil is the marginal fuel, resources burning natural gas are likely to earn inframarginal revenues, which would contribute to an increase in estimated net revenues, and both of the hypothetical resources are assumed to burn natural gas. Evidence of these inframarginal revenues earned by natural gas resources can be seen in the implied heat rate curves shown in Figure 9-5.

For both years, the analysis was performed using LMPs at the Hub. Capacity revenues were the same throughout the system. FRM revenues for the Rest-of-System zone were used for the post-ASM II period.[155]

9.4.7 Summary of Competitive Market Conditions Analyses

The energy prices have closely tracked fuel costs and changes in demand, evidence of a competitive market. More detailed analyses support the conclusion that the wholesale electricity markets in New England continued to perform competitively during 2007. The competitive benchmark analysis supports the conclusion that the observed bidding behavior is consistent with a competitive market. The residual supply index and HHI analyses indicate that New England's wholesale electricity markets continue to be structurally competitive at the system level. Even with higher average demand levels in 2007 compared with 2006, the number of hours with a pivotal supplier decreased from 154 in 2006 to 115 in 2007. At the zonal level, the New England markets are more concentrated, as evidenced by the zonal HHI values in the moderately to highly concentrated range. The INTMMU monitors for the existence of pivotal suppliers in constrained areas and is prepared to intervene if a pivotal supplier is judged to be exercising market power, as evidenced by the 13 instances during 2007 when the Market Monitor mitigated participant energy offers in the Real-Time Energy Market. The estimated net revenue of the representative combined-cycle generator in 2007 increased 51% from the 2006 estimate. If capacity payments were excluded from both years, the net revenues still would have increased by 16%.

9.5 Generating-Unit Availability

Table 9-7 reports the annual Weighted Equivalent Availability Factors (WEAF) of New England generating units for 1999 to 2007.[156] As shown, availability generally has been increasing from a low in 1996 to a new high of 90% in 2007. An undisputed benefit of the wholesale electricity markets is increased generation availability. A generator's main source of revenue is from providing electric energy, regulation, or reserve services, which require well-maintained generating resources. Moreover, reduced availability lowers the capacity payment. Market competition offers significant incentives to improve generating availability and thus reduce the amount of new investments needed.

[155] Information about the Phase II of the Ancillary Services Markets project is available online at http://www.iso-ne.com/support/faq/ph2_asm/index.html

[156] 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 9-7
New England System Weighted Equivalent Availability Factors, %[a]

	1996	1997	1998	1999[b]	2000	2001	2002	2003	2004	2005	2006	2007
System average	75	78	81	81	81	89	88	88	88	89	89	90
Fossil steam[c]	*n/a*	*n/a*	*n/a*	79	78	84	85	87	86	86	88	87
Coal	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	88	84	84	83	88	84	87
Coal/oil	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	86	74	84	88	88	85	79
Oil	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	84	86	84	84	84	89	84
Gas/oil	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	80	84	91	87	84	91	89
Wood/refuse	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	95	94	94	93	93	93	92
Nuclear	*n/a*	*n/a*	*n/a*	82	89	91	91	91	94	89	93	92
Jet engine	*n/a*	*n/a*	*n/a*	70	88	92	94	94	97	95	96	97
Combustion turbine	*n/a*	*n/a*	*n/a*	90	83	89	93	93	97	95	95	94
Combined cycle	*n/a*	*n/a*	*n/a*	83	80	84	90	85	86	86	84	86
Pre-1999 combined cycle	*n/a*	*n/a*	*n/a*	91	89	94	92	91	92	92	92	92
New (installed 1999–2004) combined cycle	*n/a*	*n/a*	*n/a*	47	67	76	90	84	84	86	81	83
Hydro	*n/a*	*n/a*	*n/a*	81	81	95	96	95	94	94	96	96
Pumped storage	*n/a*	*n/a*	*n/a*	86	86	93	87	92	90	92	91	98
Diesel	*n/a*	*n/a*	*n/a*	88	88	98	98	98	95	98	99	97

(a) The statistics for 1995 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 information 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 9-9 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 total outages in megawatts during the monthly peak-demand days in 2007 and the amount of capacity on outages as a percentage of total available seasonal claimed capability. 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-demand periods.

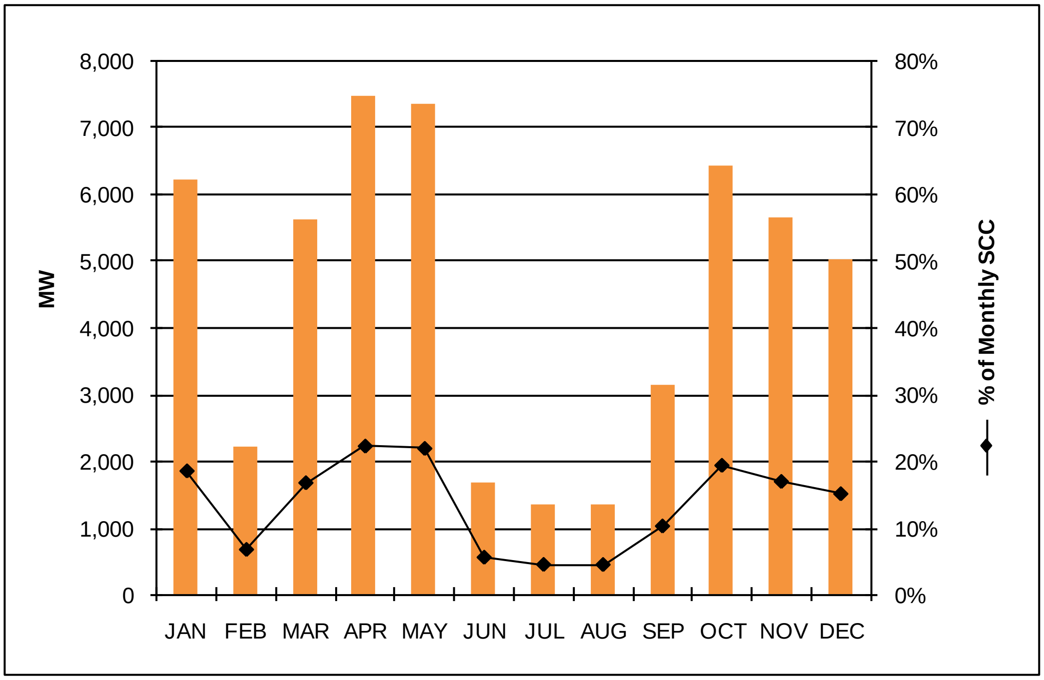

Figure 9-9: Generator-unit total outages during peak-demand days, 2007.

Figure 9-10 illustrates how the availability of the New England generating units tracks monthly demand. Specifically, Figure 9-10 illustrates the monthly WEAF and the monthly peak demand as a percentage of the annual peak demand. Similar to the information presented in Figure 9-9, the average availability for the 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. This is in accordance with outage scheduling procedures that limit outages for annual inspections to periods with lower demands.

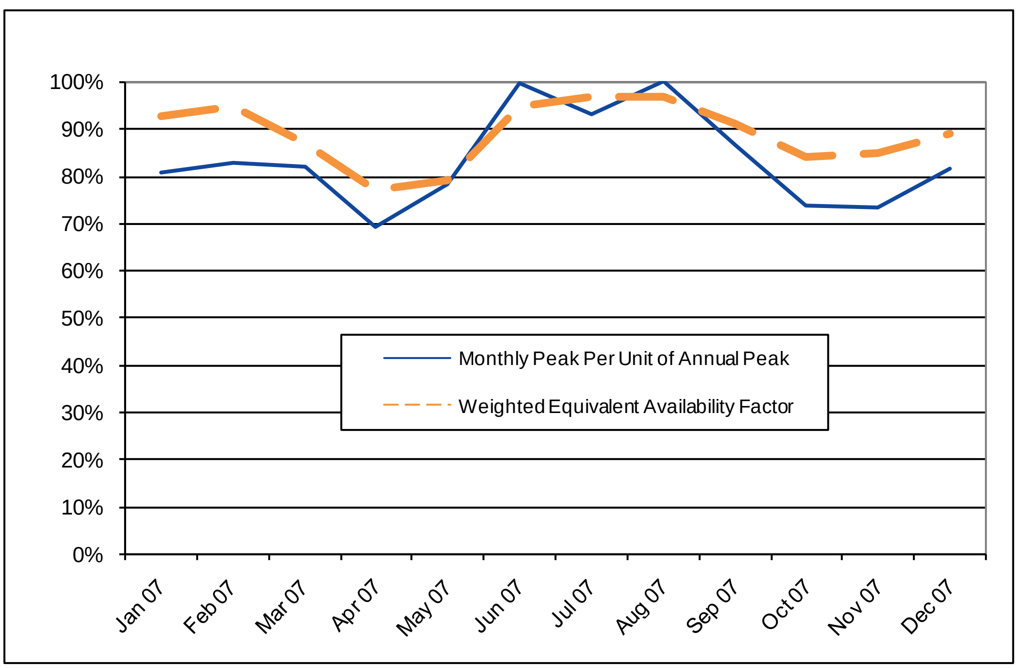

Figure 9-10: Monthly peak demand and monthly average availability (WEAF).

Figure 9-11 shows the average generation capacity (MW) on outage during each weekday peak for 1997 to 2007. The total amount of capacity on outage had been growing slightly from a low in 1998 until a peak in 2005, coincident with increases in system claimed capability. Between 2005 and 2006, the total capacity on outage decreased 10% followed by a 4% increase between 2006 and 2007. The high unplanned outages during 1997 were due to extended outages of several nuclear plants during the year.

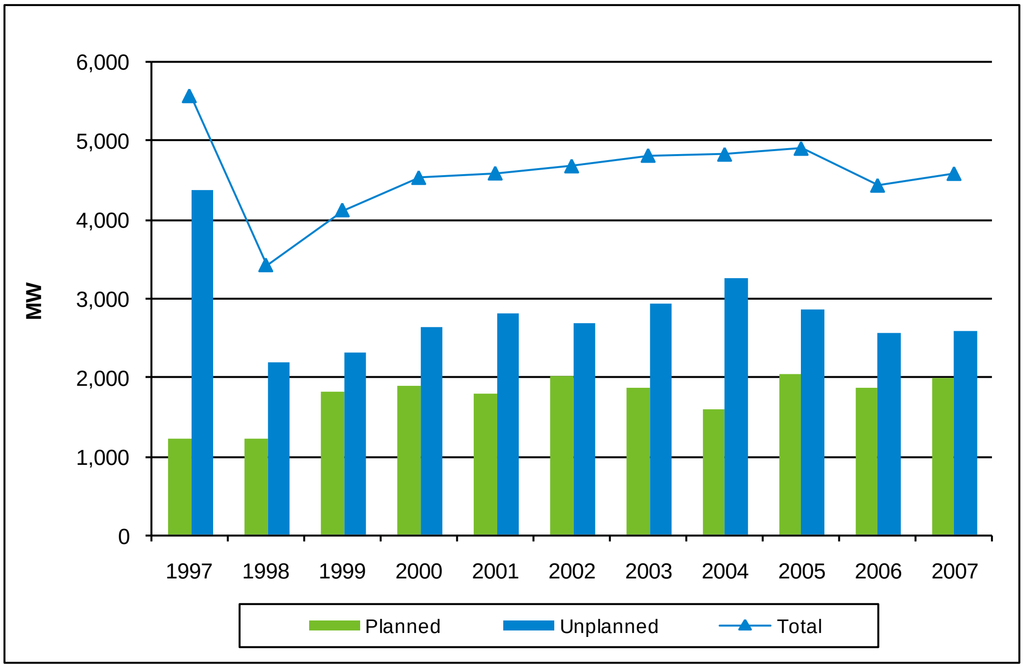

Figure 9-11: Average megawatts of outage each weekday.

Each day, the ISO commits generators that will be on line for the next day. Commitment quantities are based on forecast electrical loads and expected levels of generator availability. Between the time of commitment and the next day's peak demand, some generators experience operational problems and are forced off line. The number of generators reporting these problems has decreased since the introduction of a financial day-ahead market. Figure 9-12 shows that the loss of overnight capacity decreased significantly with the advent of the SMD's financially binding day-ahead market. For the Interim Market period, the plot compares the generator commitments made at 6:00 p.m. with the actual real-time availability of the committed generators. For SMD, the plot compares commitments in place at 10:00 p.m. (resulting from Day-Ahead Energy Market commitments as well as supplemental commitments made as part of the Reserve Adequacy Analysis) with the actual real-time availability of the committed generators. Because overnight capacity loss has decreased, fewer replacement commitments are required to address this reliability need. Lower levels of overnight capacity loss and generator outages are beneficial because they reduce the cost of committing additional generators each day to ensure that sufficient levels of generation will be available in case some of the committed generators experience forced outages.

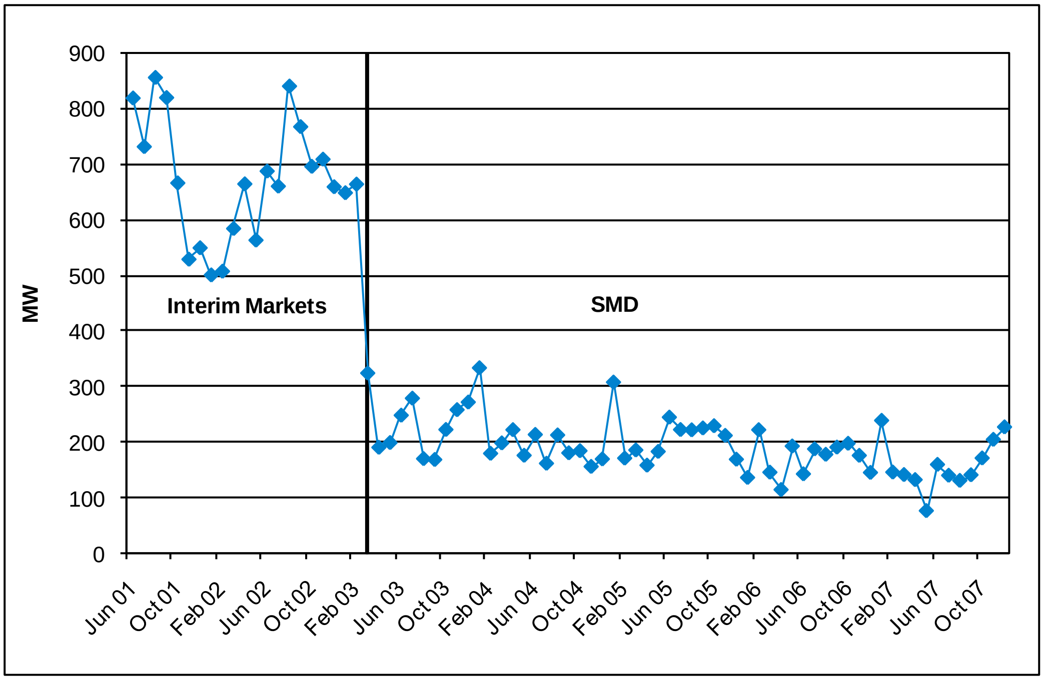

Figure 9-12: Average monthly overnight capacity loss.

Section 10
Internal ISO Market Operations Assessments

Various internal initiatives by the ISO took place in 2007 to ensure transparency of the wholesale markets. These initiatives include reviews, audits, and administrative price corrections. This section highlights the 2007 initiatives.

10.1 Audits

The ISO participated in several audits during 2007. The following audits were conducted to ensure that the ISO had followed the approved market rules and procedures and to provide transparency to New England stakeholders:

- **SAS 70 Type 2 Audit—**In October 2007, the ISO successfully passed a SAS 70 Type 2 Audit, which resulted in an "unqualified opinion" about the design and operating effectiveness of controls.[157] Developed by the American Institute of Certified Public Accountants, the SAS 70 Audit is used by service organizations to provide assurances regarding the validity and integrity of controls and systems used in the organizations' business processes. Entities such as Regional Transmission Organizations rely on SAS 70 Audits to provide assurance to the wholesale electricity marketplace regarding the validity and integrity of controls and systems used in the "bid-to-bill" business processes.

  The ISO's SAS 70 Type 2 Audit is a rigorous and detailed examination of the business processes and information technology used for activities related to bidding into the market, accounting, billing, and settling the market products of energy, regulation, transmission, capacity, demand response, and reserves. Conducted by the auditing firm KPMG LLP, the Type 2 Audit covered a 12-month period, from October 1, 2006, through September 30, 2007. The SAS 70 Type 2 Audit includes the auditor's opinion on the effectiveness of controls tested, the fairness of the description of the controls contained in the audit report prepared by the ISO, and the suitability of the design of the controls for achieving the specified objectives for the controls.[158] The ISO conducts SAS 70 Type 2 Audits annually.

- **Review of the Forward Capacity Market Project—**The ISO internal audit department is currently conducting a review of the Forward Capacity Market project including the 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.

[157] A SAS 70, *unqualified audit opinion* is issued when three conditions are met: the audit firm determines that the description of the controls in the ISO audit report (see footnote below) fairly presents the relevant aspects of the service organization's controls; the overall design of the controls is sufficient to meet the specified control objectives; and the firm has collected and evaluated sufficient competent evidence through applied tests to specific controls and determines that the controls are operating with sufficient effectiveness to provide reasonable assurance that the control objectives were achieved during the test period.

[158] KPMG. *Report on Controls Placed in Operation Pertaining to the Market Administration and Settlements Processes and Systems of ISO New England Inc. and Tests of Operating Effectiveness for the Period October 1, 2006 to September 30, 2007, Prepared Pursuant to Statement on Auditing Standards No. 70, as Amended.* (October 5, 2007). This report is available to participants on request through the ISO external Web site. See http://www.iso-ne.com/aboutiso/audit_rpts/index.html and http://www.iso-ne.com/aboutiso/audit_rpts/SAS70Request.do.

- **Market-System Software Recertification—**The ISO has committed to a practice of engaging an independent third-party, PA Consulting, to review and certify that the market system software complies with Market Rule 1, the manuals, and standard operating procedures. This recertification takes place every two years or sooner, in the case of a major market system enhancement or new market features. PA Consulting issues a compliance certificate for each market system module it audits after conducting detailed tests and analysis of the applicable mathematical formulations. The certificates provide assurance that the software is operating as intended and is consistent with Market Rule 1 and associated manuals and procedures.

In 2007, PA Consulting issued the following certifications:

- Auction Revenue Rights Market Software, October 4, 2007
- Financial Transmission Rights Market Software, October 4, 2007
- Locational Marginal Price Calculator Market Software, November 1, 2007
- Scheduling, Pricing and Dispatch—Day Ahead Market Software, November 1, 2007
- Scheduling, Pricing and Dispatch—Unit Dispatch System Market Software, November 1, 2007

All certificates are available to participants on request through the ISO external Web site.[159]

10.2 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 as accurate as reasonably possible. 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, corrections to LMPs were required in 144 hours (1.6%) during 2007, down from 190 hours in 2006.

Price corrections at inactive (*dead)* buses accounted for price changes in 84 hours in 2007. A *dead bus* results when 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.

In 2007, price corrections to five-minute LMPs were required in 47 hours because of data errors or software limitations. The LMP calculator runs every five minutes and requires information from an approved unit dispatch system (UDS) case for the five-minute period in question. If the required UDS case has not been approved before the scheduled execution of the LMP calculator, a mismatch of data can occur, resulting in an incorrectly calculated LMP for that five-minute interval. This problem

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

typically occurs for one of two reasons. One reason is that the status of a constraint changes between the time when the UDS case accesses data and when the LMP calculator produces results for the five-minute period. The other reason is that the data sent to the LMP calculator may not reflect the actual constraints because a UDS case was not properly approved or does not fully reflect actual system conditions for the applicable five-minute periods. This issue typically affects only one five-minute interval and therefore has a minor impact on the hourly integrated LMPs.

In 2007, scheduled system maintenance required price corrections in 10 hours, while unplanned outages resulted in price corrections in three hours. Corrections to hourly prices are required when hardware or software systems are unavailable. Systems can be unavailable for brief periods when switching from primary to backup systems to conduct routine maintenance and for periods of unplanned outages resulting from hardware or software failures. When this happens, the ISO manually calculates prices for the missing data intervals.

The ISO also continuously monitors the processes for calculating regulation clearing prices. In total, price corrections to RCPs were required in six hours during 2007, which is 0.07% of the hours in the year. Data errors resulted in RCP corrections in three hours and scheduled system maintenance required RCP corrections in three hours.

Appendix A
Electricity Market Statistics

A.1 Energy Market Volumes

Table A-1 and Table A-2 present information about the megawatt-hour quantity of electricity transactions in the Day-Ahead and Real-Time Energy Markets. Participant transactions to buy and sell electricity executed by submitting bids and offers into the Day-Ahead and Real-Time Energy Markets are settled at the applicable day-ahead or real-time LMPs. Participants also may enter into contracts with each other at mutually agreed-on prices. Some of these contracts are submitted for scheduling in either the Day-Ahead or Real-Time Energy Market. Participants may enter into *internal* contracts, under which electric energy is bought and sold for generation and delivery within the New England area, or they may enter into *external* contracts, under which either generation or delivery occurs outside New England.

Table A-1
Day-Ahead and Real-Time Energy Market Quantities Traded by Transaction Type, January to June 2007, MWh

Transaction Type by Market	Jan 07	Feb 07	Mar 07	Apr 07	May 07	Jun 07
Day Ahead						
Load obligation—day-ahead LMP	12,867,040	11,842,976	11,815,798	10,739,429	11,027,589	12,283,605
Bilateral— export with price	*32,932*	*35,874*	*99,949*	*65,396*	*66,176*	*105,877*
Bilateral— export without price	*270,575*	*262,875*	*361,437*	*469,928*	*366,749*	*497,371*
Bilateral— export up-to congestion	*673*	*365*	*20,090*	*12,758*	*4,082*	*36,118*
Bilateral— internal for market day ahead (IBM)	6,611,324	6,244,646	6,434,641	6,430,820	7,069,191	7,411,609
Bilateral— import with price	*52,408*	*68,500*	*230,734*	*208,483*	*290,678*	*119,680*
Bilateral— import without price	*1,209,350*	*1,234,589*	*869,438*	*851,220*	*875,915*	*889,101*
Bilateral— import up-to congestion	41,010	12,440	23,059	13,572	36,875	34,507
Total day ahead MWhs	**20,781,132**	**19,403,151**	**19,373,670**	**18,243,525**	**19,300,247**	**20,738,502**
Real Time						
Adjusted load-obligation deviation—real-time LMP	–562,030	–446,677	–22,835	65,629	105,738	–394,431
Adjusted load-obligation deviation—lower than day ahead	–1,825,480	–1,612,579	–1,495,298	–1,300,687	–1,467,587	–1,926,445
Adjusted load-obligation deviation—higher than day ahead	1,263,450	1,165,902	1,472,463	1,366,316	1,573,325	1,532,015
Bilateral—export with price	*3,071*	*267*	*0*	*308*	*0*	*9,393*
Bilateral—export without price	*529,031*	*446,916*	*623,753*	*716,713*	*686,081*	*733,458*
Bilateral— internal for market - additional to day-ahead IBMs	83,004	103,611	106,030	100,631	106,426	112,671
Bilateral— internal for load, real time	0	0	0	0	0	0
Bilateral— import with price	*0*	*0*	*55,844*	*92,225*	*262,020*	*100,735*
Bilateral—import without price	*1,473,583*	*1,514,602*	*1,282,241*	*1,225,241*	*1,271,327*	*1,127,036*
Bilateral—through	5,169	2,433	2,553	2,236	2,344	1,738
Total real time MWhs	**999,725**	**1,173,969**	**1,423,833**	**1,485,962**	**1,747,855**	**947,749**
Net energy for load (000s of MWh)	***11,754***	***10,983***	***11,202***	***10,137***	***10,455***	***11,139***

(a) The *day-ahead load obligation for energy* is equal to the megawatt-hours of demand bids, virtual demand bids, and external transaction sales cleared in the Day-Ahead Energy Market. It is settled at the day-ahead LMP. The figure reported here is the systemwide total of participants' locational load obligations. It is reported here as a positive number; however, it is calculated on an individual participant level as a negative number.

(b) Exports are included in load obligation.

(c) The *real-time adjusted load-obligation deviation* is the difference between real-time and day-ahead load obligations. It is settled at the real-time LMP. The figure reported here is the systemwide total of participants' locational adjusted load-obligation deviations. Adjusted load-obligation deviation may be negative (indicating a lower load obligation cleared day ahead) or positive (indicating a higher load obligation cleared day ahead). The signage used here is reversed from the signage used in participant-level calculations. Because much of the real-time deviations from day ahead at the participant level net to zero when the systemwide total is calculated, the total of negative deviations and the total of positive deviations are shown here to give a sense of the magnitude of activity in the Real-Time Energy Market.

Table A-2
Day-Ahead and Real-Time Energy Market Quantities Traded by Transaction Type, July to December 2007, MWh

Transaction Type by Market	Jul 07	Aug 07	Sep 07	Oct 07	Nov 07	Dec 07
Day Ahead						
Load obligation—day-ahead LMP	14,020,892	14,327,411	12,150,790	11,558,481	11,434,874	12,376,561
Bilateral—export with price	*288,663*	*299,539*	*207,936*	*73,488*	*87,549*	*44,801*
Bilateral—export without price	*625,327*	*609,234*	*457,704*	*457,629*	*480,802*	*375,215*
Bilateral—export up-to congestion	*1,763*	*6,211*	*14,945*	*11,242*	*17,685*	*0*
Bilateral—internal for market day ahead (IBM)	7,696,144	8,034,887	7,369,306	7,568,079	7,275,261	7,602,047
Bilateral—import with price	*59,354*	*87,141*	*51,888*	*19,674*	*120,853*	*226,813*
Bilateral—import without price	*781,463*	*722,357*	*518,876*	*467,683*	*867,575*	*824,602*
Bilateral— import up-to congestion	28,881	35,405	24,491	53,560	43,924	4,386
Total day-ahead MWhs	**22,586,734**	**23,207,200**	**20,115,351**	**19,667,477**	**19,742,488**	**21,034,408**
Real Time						
Adjusted load-obligation deviation—real-time LMP	–531,266	–534,097	–404,999	–195,141	– 24,125	–5,716
Adjusted load-obligation deviation—lower than day ahead	–2,234,960	–2,282,170	–2,002,898	–1,736,403	–1,636,625	–1,508,503
Adjusted load-obligation deviation—higher than day ahead	1,703,693	1,748,072	1,597,899	1,541,263	1,512,500	1,502,787
Bilateral—export with price	*23,395*	*780*	*6,709*	*0*	*0*	*15,718*
Bilateral—export without price	*1,049,095*	*1,053,765*	*841,572*	*690,266*	*735,952*	*528,649*
Bilateral—internal for market - additional to day-ahead IBMs	112,227	109,761	92,966	98,234	79,534	100,261
Bilateral—internal for load, real time	0	0	0	48,850	0	0
Bilateral—import with price	*59,635*	*94,130*	*71,645*	*63,680*	*151,180*	*80,654*
Bilateral—import without price	*1,024,088*	*1,013,275*	*756,563*	*654,239*	*1,090,029*	*1,266,591*
Bilateral—through	541	0	1,512	272	498	256
Total real-time MWhs	**665,225**	**683,068**	**517,687**	**670,135**	**1,197,117**	**1,442,046**
Net energy for load (000s of MWh)	***12,380***	***12,656***	***10,778***	***10,594***	***10,542***	***11,805***

(a), (b), (c) See notes for Table A-1.

External contracts may be submitted with or without a price. *With-price* contract purchases and sales will not flow unless transfer capacity is available, conforming arrangements with the external system are in place, and the New England LMP is above the specified price level for purchases or below the specified price levels for sales. *Without-price* contracts flow under the assumption that transfer capacity and conforming arrangements with the external system are available.

External contracts in the Day-Ahead Energy Market also may be submitted as *up-to-congestion* contracts. These contracts do not flow if the congestion charge is above a specified level. Real-time external transactions cannot be submitted as up-to-congestion contracts; participants with real-time external transactions are considered to be always willing to pay congestion charges. *Wheel-through* contracts also are submitted into the market system for scheduling.

In New England, the volume of electricity traded exceeds actual load. Day-ahead load obligations (MWh) settled at the day-ahead LMP are close to actual load; in some hours, quantities exceed actual load. Also, internal bilateral contract quantities typically are greater than actual load. These numbers show that the Day-Ahead Energy Market is widely used to settle expected real-time load and generation obligations. Internal bilateral contracts cover much of either day-ahead or actual real-time load obligations. Most import contracts generally are without-price contracts, which are equivalent to self-scheduled imports.

A.2 Electric Energy Prices

Tables A-3 to A-6 show 2007 LMP summary statistics for on- and off-peak hours and the monthly average day-ahead and real-time locational marginal prices by zone. On-peak hours are all hours between 7:00 a.m. and 11:00 p.m. during weekdays that are not NERC holidays. All other hours are off-peak hours.

Table A-3
LMP Summary Statistics, On-Peak Hours, January to December 2007

Location	Avg. Day-Ahead LMP ($/MWh)	Avg. Real-Time LMP ($/MWh)	Min. Day-Ahead LMP ($/MWh)	Min. Real-Time LMP ($/MWh)	Max. Day-Ahead LMP ($/MWh)	Max. Real-Time LMP ($/MWh)
Internal Hub Load Zone	77.00	75.25	44.21	19.69	207.35	265.49
Maine Load Zone	72.07	71.17	42.21	18.85	194.99	817.08
New Hampshire Load Zone	75.45	74.54	43.21	19.33	184.95	497.85
Vermont Load Zone	78.91	77.32	43.78	19.75	195.82	269.29
Connecticut Load Zone	82.94	84.34	43.95	20.08	205.4	631.65
Rhode Island Load Zone	74.47	72.83	43.62	19.88	206.04	262.01
SEMA Load Zone	76.98	74.71	43.85	24.08	208.45	264.01
WCMA Load Zone	77.79	76.51	44.16	19.82	206.96	267.11
NEMA Load Zone	75.01	73.81	43.35	19.48	209.08	282.59
NB–NE External Node	70.27	68.08	37.3	11.67	196.24	482.14
NY–NE AC External Node	79.53	79.38	43.63	19.78	200	328.99
HQ Phase I/II External Node	73.64	72.03	42.8	-3.89	209.62	258.93
Highgate External Node	74.44	72.08	41	18.08	182.32	251.35
Cross-Sound Cable External Node	82.49	81.61	44.13	19.2	204.78	387.06
1385 Cable	86.38	85.34	47.35	25.63	267.14	449.83

Table A-4
LMP Summary Statistics, Off-Peak Hours, January to December 2007

Location	Avg. Day-Ahead LMP ($/MWh)	Avg. Real-Time LMP ($/MWh)	Min. Day-Ahead LMP ($/MWh)	Min. Real-Time LMP ($/MWh)	Max. Day-Ahead LMP ($/MWh)	Max. Real-Time LMP ($/MWh)
Internal Hub	60.10	59.28	25.18	0	197.32	297.92
Maine Load Zone	57.62	57.10	21.47	0	169.38	287.88
New Hampshire Load Zone	59.31	58.53	24.62	0	188.47	295.63
Vermont Load Zone	61.00	60.08	24.94	0	193.04	300.39
Connecticut Load Zone	61.89	60.77	24.73	0	195.23	329.97
Rhode Island Load Zone	58.93	58.27	24.85	0	196.46	294.4
SEMA Load Zone	60.07	58.76	24.98	0	202.93	295.71
WCMA Load Zone	60.50	59.63	25.16	0	196.78	300.1
NEMA Load Zone	59.33	58.44	24.69	0	199.74	331.76
NB–NE External Node	56.26	55.87	20.09	0	180.5	267.41
NY–NE AC External Node	60.92	60.03	23.41	0	190	301.8
HQ Phase I/II External Node	58.30	57.70	24.38	0	200.71	286.68
Highgate External Node	57.80	57.36	23.36	0	180.86	281.44
Cross-Sound Cable External Node	61.85	61.01	24.81	0	194.76	307.44
1385 Cable	62.35	61.00	24.83	0	195.25	356.06

Table A-5
Monthly Average Day-Ahead LMPs by Zone, 2007

Month	Hub	Maine	NH	VT	CT	RI	SEMA	WCMA	NEMA
Jan	63.25	57.39	59.95	64.09	65.02	59.66	61.05	63.30	59.33
Feb	81.30	77.70	80.18	83.32	84.22	78.87	80.12	82.27	78.96
Mar	69.40	64.43	67.67	69.53	71.86	67.22	68.59	69.68	67.40
Apr	70.47	66.10	68.17	70.51	74.63	68.95	69.49	71.07	68.86
May	67.33	61.63	65.72	68.97	70.90	64.50	65.97	68.01	65.86
Jun	63.74	59.87	62.55	66.91	68.89	62.08	64.58	64.80	62.20
Jul	60.81	57.75	60.38	62.89	66.13	59.80	64.26	61.72	60.29
Aug	66.34	62.74	66.07	68.80	70.67	64.51	67.64	67.05	65.36
Sep	58.93	55.23	58.81	60.74	63.04	57.45	58.85	59.25	58.48
Oct	59.87	59.43	59.91	61.14	65.75	58.25	59.99	60.27	59.91
Nov	62.63	60.43	61.56	63.09	65.66	62.06	62.99	63.16	61.86
Dec	92.33	90.26	91.77	92.98	94.33	91.40	92.55	92.86	91.80

Table A-6
Monthly Average Real-Time LMPs by Zone, 2007

Month	Hub	Maine	NH	VT	CT	RI	SEMA	WCMA	NEMA
Jan	60.75	56.01	58.67	62.30	62.96	58.17	58.77	61.19	58.02
Feb	79.55	75.88	78.52	80.92	81.56	77.57	77.94	80.24	77.56
Mar	65.77	62.03	64.43	67.25	72.91	63.47	64.95	66.29	64.45
Apr	67.45	63.92	65.77	67.32	72.88	66.51	66.61	67.96	65.82
May	67.47	62.17	66.14	69.98	76.65	64.17	65.51	68.54	65.50
Jun	60.61	57.68	59.96	62.24	67.31	59.58	60.49	61.79	60.09
Jul	61.18	57.86	60.45	62.71	66.62	59.90	63.34	62.55	60.41
Aug	65.08	60.94	64.96	67.32	73.38	63.25	64.47	66.26	63.96
Sep	60.74	59.76	61.96	62.64	64.40	59.13	59.97	61.22	61.13
Oct	59.65	59.68	59.64	60.81	65.10	58.15	60.09	60.18	58.99
Nov	61.10	59.24	60.37	61.61	64.39	60.56	61.14	61.90	60.35
Dec	91.97	89.37	91.70	92.83	93.23	90.90	91.58	92.49	91.57

A.3 Average Electric Energy Prices for ISO New England, NYISO, and PJM, 2007

Table A-7 shows yearly average system prices for ISO New England, NYISO, and PJM.

Table A-7
ISO New England, NYISO, and PJM Average Electric Energy Prices, 2007, $/MWh

Control Area	Day Ahead			Real Time		
	All	On Peak	Off Peak	All	On Peak	Off Peak
ISO New England	$61.80	$71.04	$53.44	$60.48	$70.12	$51.75
NYISO	$65.70	$77.92	$54.63	$64.94	$79.23	$52.09
PJM	$48.10	$58.86	$38.36	$49.27	$60.69	$38.94

A.4 Description of All-In-Cost Metric Components

Daily Reliability Payments—From May 1, 1999, to June 30, 2001, daily reliability included energy uplift and congestion uplift. Payments for VAR (voltage ampere reactive) control were included in congestion uplift. From July 1, 2001, to February 28, 2003, daily reliability included economic Net Commitment-Period Compensation and noneconomic NCPC. Payments for VAR control were included in noneconomic NCPC. From March 1, 2003, to December 31, 2007, daily reliability included first-contingency NCPC and second-contingency NCPC and voltage and distribution reliability payments. See Section 6 for additional information on NCPC.

Ancillary Services—From May 1, 1999, to February 28, 2003, ancillary services included payments for automatic generation control (AGC), 10-minute spinning reserves, 10-minute nonsynchronized reserves, and 30-minute reserves. From March 1, 2003, to December 31, 2003, ancillary services included Regulation Market payments. From January 1, 2004, to December 31, 2007, ancillary services included Regulation Market and Forward Reserve Market payments.

Capacity—From May 1, 1999, to November 30, 2006, capacity included payments to resources in the ICAP markets. This does not include payments from the bilateral markets or payments associated with self-supplied installed capacity. From December 1, 2006, to December 31, 2007, capacity included Forward Capacity Market transition payments.

Appendix B
Forward Reserve Market Offer Curves

Figure B-1 through Figure B-6 show supply curves for each reserve area and product. The supply curves are not adjusted downward for the subtraction of capacity transition payments (see Section 3). FRM payments are reduced by transition payments, which were $3,050/MW-month in 2007. Thus, an FRM offer of $3,050/MW-month would net the supplier $0 if it were the marginal offer.

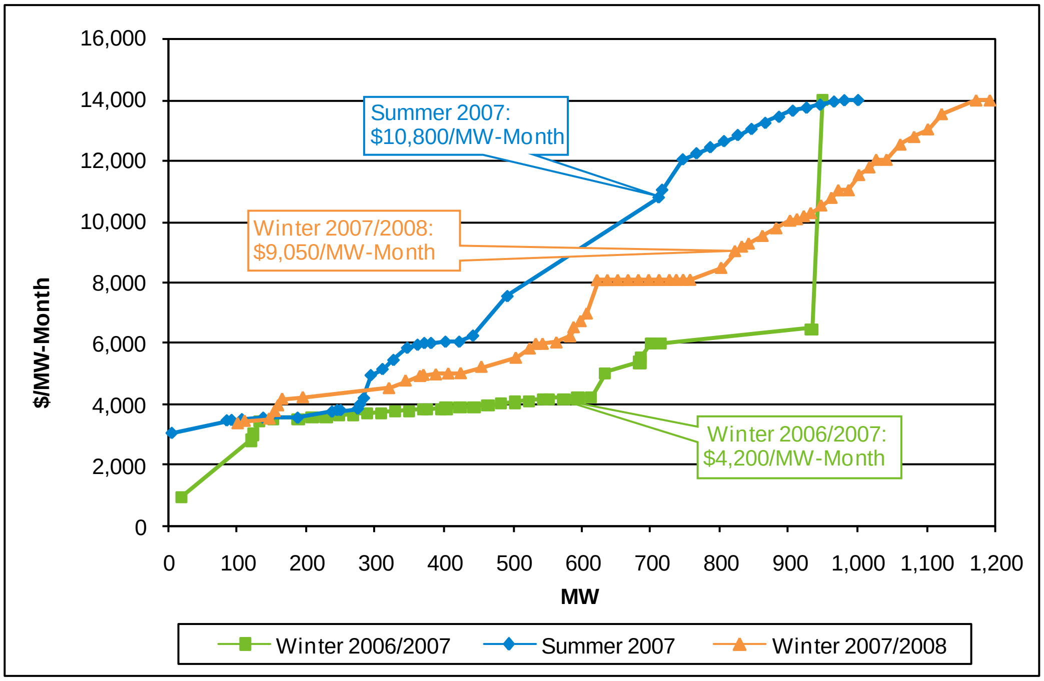

Figure B-1: Rest-of-System TMNSR offer curves, winter 2006/2007, summer 2007, and winter 2007/2008 forward-reserve auctions.

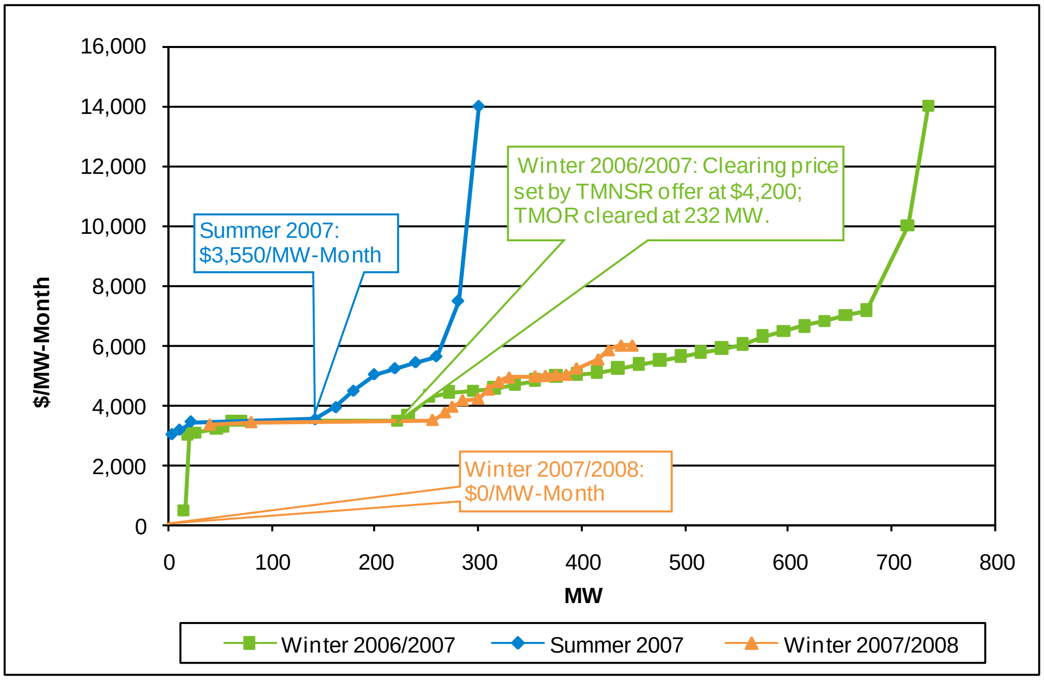

Figure B-2: Rest-of-System TMOR offer curves, winter 2006/2007, summer 2007, and winter 2007/2008 forward-reserve auctions.

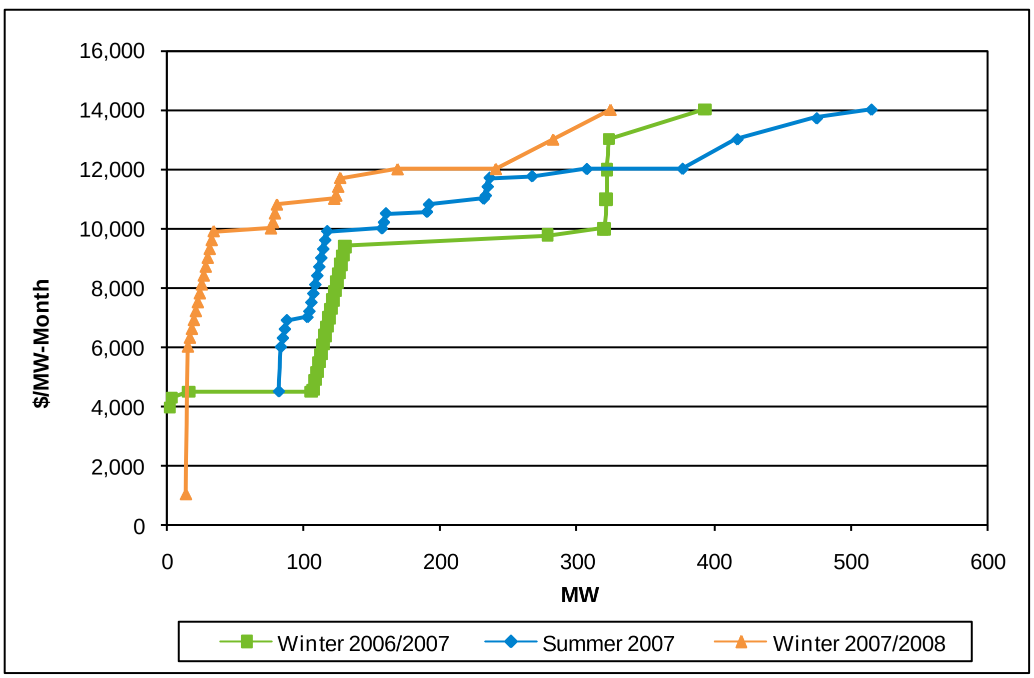

Figure B-3: SWCT TMOR offer curves, winter 2006/2007, summer 2007, and winter 2007/2008 forward-reserve auctions.

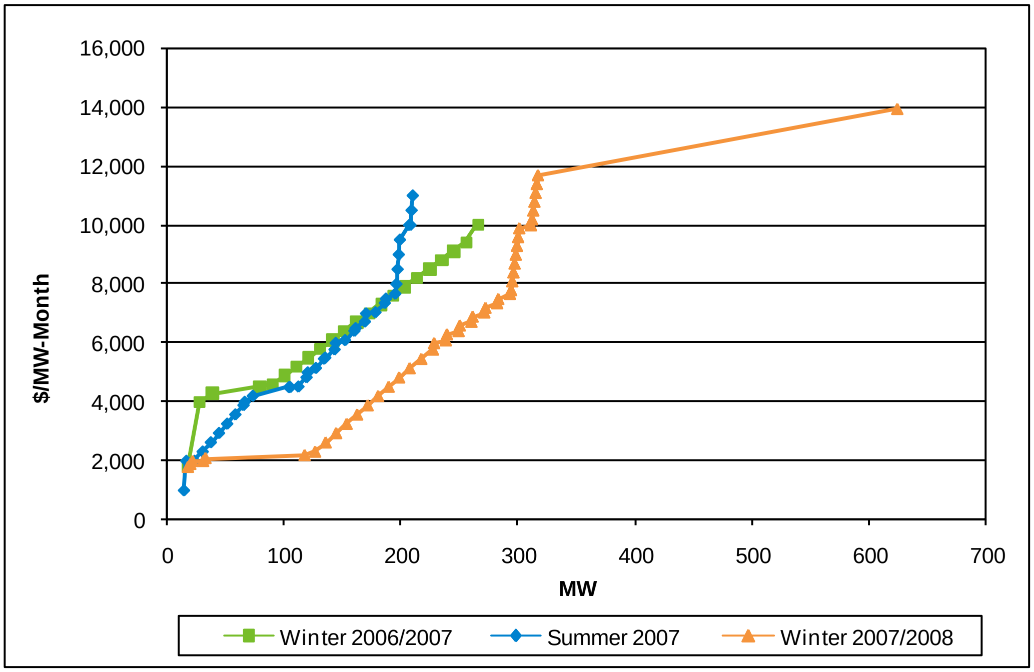

Figure B-4: CT TMOR offer curves, winter 2006/2007, summer 2007, and winter 2007/2008 forward-reserve auctions.

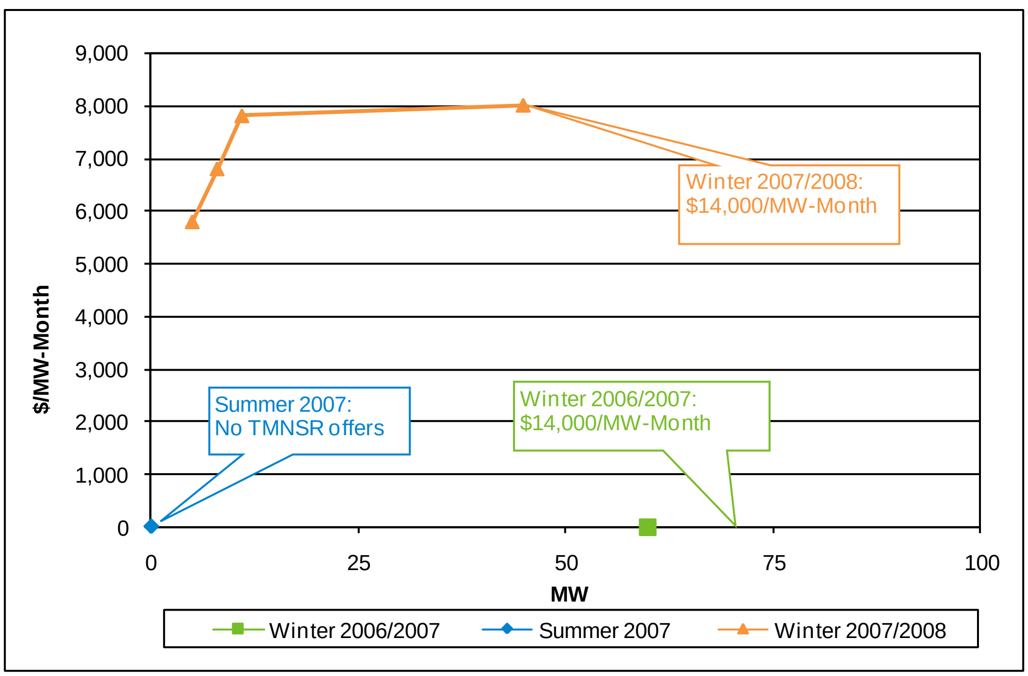

Figure B-5: NEMA/Boston TMNSR offer curves, winter 2006/2007, summer 2007, and winter 2007/2008 forward-reserve auctions.

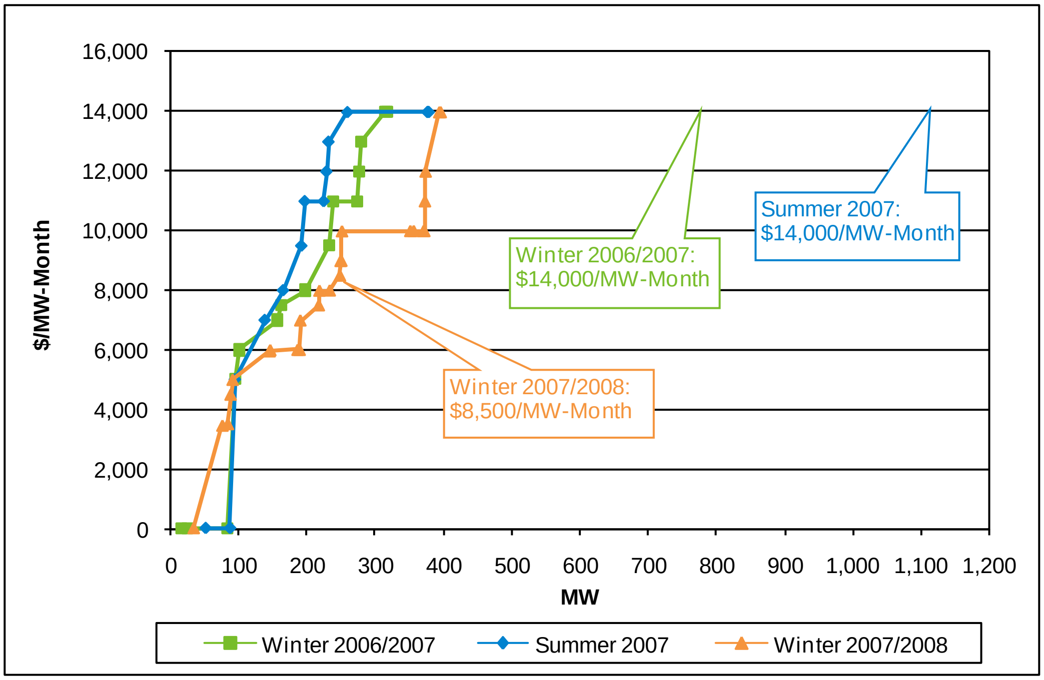

Figure B-6: NEMA/Boston TMOR offer curves, winter 2006/2007, summer 2007, and winter 2007/2008 forward-reserve auctions.

Appendix C
Other Tariff Charges and the Congestion Revenue Balancing Fund

Appendix C provides supplemental cost components of the ISO *Self-Funding Tariff* and the *Open Access Transmission Tariff* and the Congestion Revenue Balancing Fund.

C.1 Other Tariff Charges

In 2006, participants paid for administrative and transmission services under the ISO *Self-Funding Tariff* and the *Open Access Transmission Tariff* (both of which are part of the Transmission Tariff).

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

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

Total payments under each ISO schedule are shown in Table C-1.

Table C-1
ISO *Self-Funding Tariff* Charges

Date	Schedule 1: Scheduling, System Control, and Dispatch Service	Schedule 2: Energy Administration Service	Schedule 3: Reliability Administration Service
2007 Total	$23,154,613	$53,108,170	$36,066,537

Transmission services were paid for under the OATT. These services are as follows:

- **Schedule 1: Scheduling, System Control, and Dispatch Service—**involves scheduling and administering the movement of power through, out of, or within the New England Control Area.
- **Schedule 2: Reactive Supply and Voltage Control (VAR)—**provides reactive power to maintain transmission voltages within acceptable ranges. Schedule 2 also includes calculations for capacity costs (CC).
- **Schedule 8: Through or Out Service (TOUT)—**includes transactions that go through the New England Control Area or originate on a Pool Transmission Facility (PTF) and flow over

the PTF before passing out of the New England Control Area. Transmission customers pay the PTF rate for TOUT service reserved for them with respect to these transactions.

- **Schedule 9: Regional Network Service (RNS)—**is an ISO accounting service for regional network services. RNS allows network customers to efficiently and economically use their resources, internal bilateral transactions, and external transactions to serve their network load located in the New England area.

- **Schedule 16: System Restoration and Planning Service (Black Start)—**plans for and maintains adequate capability for the restoration of the New England Control Area following a blackout.

- **Schedule 19: Special-Constraint Resource (SCR) Service of the *Open Access Transmission Tariff* —**includes the payments and charges for the out-of-merit commitment or operation of resources at the request of transmission owners or distribution companies to manage constraints not reflected in the ISO systems.

Total payments under each OATT schedule are shown in Table C-2.

Table C-2
OATT Charges

Date	Schedule 1	Schedule 2: CC	Schedule 2: VAR	Schedule 8: TOUT	Schedule 9: RNS	Schedule 16: Black Start	Schedule 19: SCR
2007 Total	$27,424,202	$18,843,991	$46,004,988	$5,903,063	$581,617,269	$10,344,844	$1,848,025

C.2 Transmission Congestion Revenue Fund

Table C-3 shows details about the accounting for the Transmission Congestion Revenue Fund, and Figure C-1 shows the relationship between FTR auction awards, energy market congestion, and FTR settlements.

Table C-3
Details of the 2007 Transmission Congestion Revenue Fund, $

Month	Fund Adjustment	Day-Ahead Congestion Revenue	Real-Time Congestion Revenue	Negative Target Allocation (paid in by participants)	Positive Target Allocation (paid out to participants)	Amount Paid Out to Positive Target Allocations	Monthly Fund Surplus or Shortfall	Interest	Ending Balance	Cumulative Balance for Year End	Percent Positive Allocation Paid
Jan	44,354	9,759,970	–2,938,756	8,567,058	–17,113,217	–15,432,626	–1,680,591	0	0	0	90
Feb	20,285	5,530,448	–1,054,643	3,985,262	–9,034,375	–8,481,352	–553,023	0	0	0	94
Mar	10,814	12,998,680	–4,401,633	6,570,084	–17,522,674	–15,177,946	–2,344,728	0	0	0	87
Apr	96	8,219,531	–303,743	3,631,264	–11,518,292	–11,518,292	28,855	15,743	44,598	44,598	100
May	623	14,021,210	–222,907	10,064,586	–20,434,289	–20,434,289	3,429,223	22,368	3,451,591	3,496,189	100
Jun	809	13,914,953	–1,417,732	7,825,638	–18,307,182	–18,307,182	2,016,486	34,089	2,050,575	5,546,764	100
Jul	30,046	15,562,340	–2,133,607	7,256,242	–21,333,474	–20,715,021	–618,453	23,131	23,131	5,569,895	97
Aug	35,433	15,058,856	–3,900,624	5,447,628	–19,891,761	–16,641,293	–3,250,469	23,101	23,101	5,592,996	84
Sep	22,431	12,319,271	129,367	4,390,331	–19,708,794	–16,861,399	–2,847,395	21,729	21,729	5,614,726	86
Oct	22,240	12,482,899	–1,234,365	5,610,585	–22,015,869	–16,881,359	–5,134,510	21,661	21,661	5,636,387	77
Nov	17,926	4,084,168	–401,302	2,225,391	–6,129,306	–5,926,182	–203,124	19,938	19,938	5,656,325	97
Dec	998	6,193,537	143,349	3,616,337	–8,483,939	–8,483,939	1,470,283	26,689	1,496,971	7,153,296	100

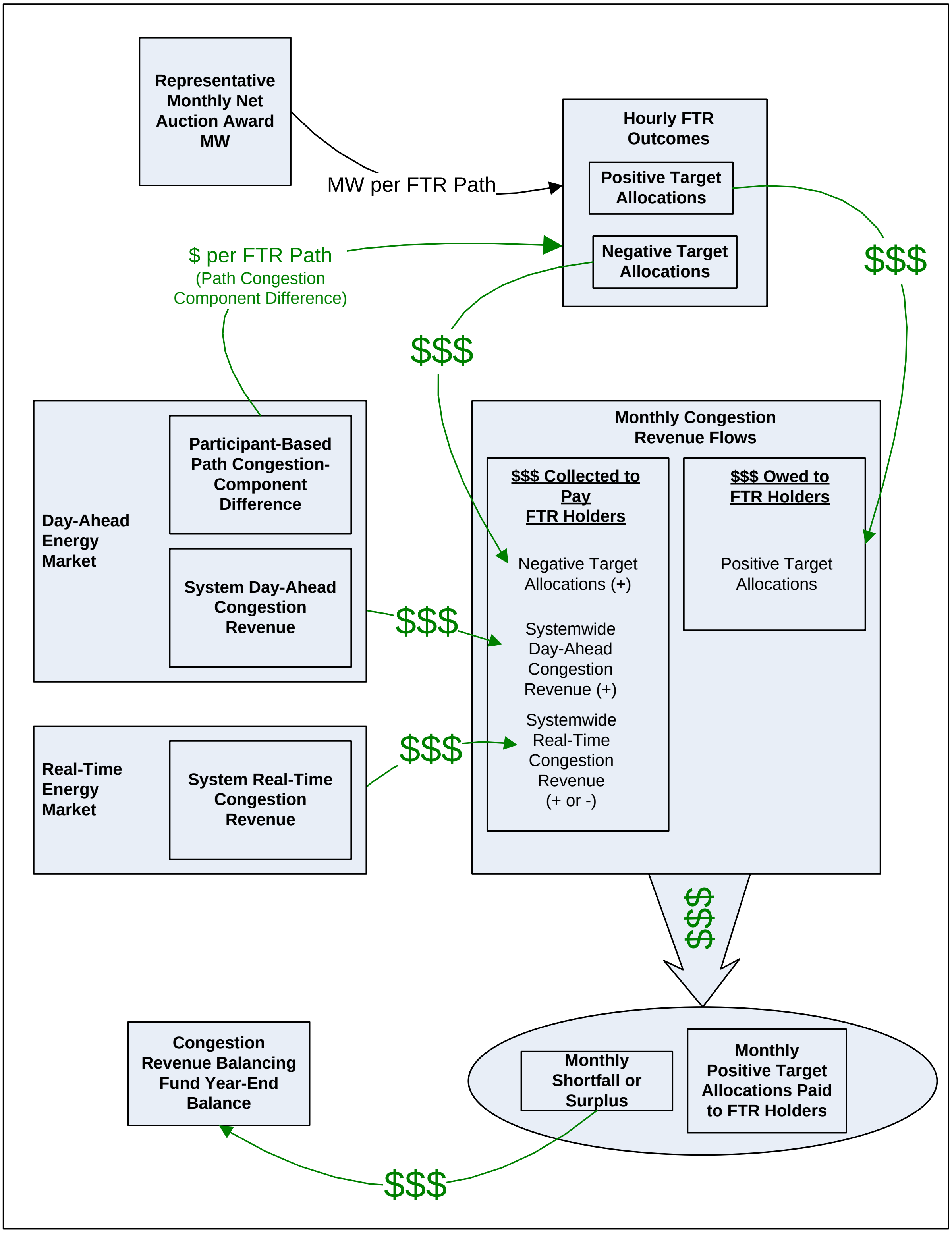

Figure C-1: Flow diagram of FTR and energy market interactions.